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STEAM INJECTION EXPERIMENTS IN SCALED PHYSICAL MODELS

FINAL REPORT

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MICROMEDIA

FOREWARD

This final report covers the period of July 1, 1985 to June 30, 1987 of the subject project. During this period, the work initiated in Phase I (contract DSS EMR OST83-00212) was continued. Minor changes in the original apparatus were made, and numerous experiments were conducted. Work was also continued on numerical simulation, with features such as foam flow and bottom water. Three papers on the experimental work were presented during this period, which are included in Appendix F. The work completed to date has pointed the way for Phase III of this project.

The technical assistance provided by Dr. Albert George is gratefully acknowledged. Mr. Roger Lafleur's cooperation in the final phase of this report is appreciated. Thanks are also expressed to Dr.K.W.A. Miller for providing information on the Aberfeldy reservoir, which served as the prototype, and to Dr. G.S. Reddy, for suggesting a number of simulation studies, both of Husky Oil Operations Ltd., Calgary.

The financial assistance of CANMET/Energy Mines and Resources Canada is acknowledged, which made this research possible and contributed to the graduate program of the Department of Mining, Metallurgical, and Petroleum Engineering. Mr. M. Proctor obtained an M.Sc. degree and Ms. Mahnaz Kasraie a Ph. D. degree on the basis of this research.

EXECUTIVE SUMMARY

This research was directed toward a theoretical and experimental study of steamflooding variations with the objective of optimizing oil recovery from thin, heavy oil formations, with bottom water present in many instances. The work addressed the Lloydminster type reservoirs, in particular the Aberfeldy reservoir which is characterized by a viscous oil (1275 mPa·s at reservoir temperature), thin pay, and bottom water in some areas. However, it is felt that the steam injection concepts tested in this research will be applicable to many heavy oil reservoirs which are underlain by bottom water, including the Cold Lake heavy oil formations. The relatively low viscosity of the Lloydminster heavy oils, however, offers the prospect of near term development.

Numerical Simulation

Steam injection in the form of cyclic steam stimulation and steamflooding has been highly successful as an enhanced oil recovery technique. This study deals with the mathematical simulation of steam injection processes, with special reference to several phenomena, thus far not considered. These are: thermal upgrading of oil, non-Newtonian oil rheology and injection of foam. In addition, a number of steam injection strategies were studied for bottom water heavy oil reservoirs. One of these is the case of partial penetration in formations containing a bottom water layer. Both steamfloods and cyclic steam stimulation were simulated for partially penetrating wells. Another new feature studied in this work is the case of multiple layer steam injection from a single tubing. For this purpose, a wellbore heat loss model was used for multiple offtake. It was found that the steam quality can vary considerably in such a case, with the lower zone taking steam of lower quality than the upper zone. Finally, the case of gas injection with steam was also investigated for cyclic steam stimulation.

A fully implicit formulation was employed in the simulation. The finite difference equations were solved using a block matrix band equation solving algorithm. Thermal

upgrading, non-Newtonian flow, and foam injection were incorporated into the mathematical model, using the published experimental data. The purpose here was to show the qualitative effects in each of these cases, rather than a comprehensive study of each of these effects. It was found that if the oil is shear thinning, the oil recovery and oil-steam ratio are likely to increase. Thermal upgrading may lead to a small recovery increase, if long times are involved. Foam was not particularly effective in increasing oil recovery. In this work, the foam was considered as an agent for decreasing gas phase mobility. Injection of natural gas with steam, in cyclic steam stimulation, was found to increase the oil-steam ratio only marginally.

Experimental Work

The work is a continuation of the previous contract (DSS EMR OST83-00212) and utilizes basically the same experimental apparatus. The apparatus was designed to represent one-quarter of an eight hectare (twenty acre) five-spot pattern and was scaled based upon low pressure scaling. Modifications of the original apparatus were required, the details of which are given later in this report.

Based on observations and experiences gained from previous experiments, several new types of experiments were conducted in an attempt to develop steamflooding variations which are likely to succeed in the field.

Twenty-three experiments were conducted in the low pressure scaled model, including continuous steamfloods into homogeneous packs, continuous steamfloods into bottom water packs, gas injection experiments in bottom water packs in which a small volume of gas was injected into the upper part of the reservoir prior to steam injection, steamflood experiments utilizing horizontal wells, and solvent injection experiments.

It was found that by injecting an inert gas into the model, prior to steamflooding, the effect of thick bottom water zones can be minimized. Temperature profiles indicated that the injected gas created a flow channel away from the water zone, and that the injected steam tended to follow this path of least resistance, rather than channeling directly into the

bottom water zone. Injecting gas into a bottom water model, prior to steamflooding improved the oil recovery from 16.79% to 20.66% of the original oil in place.

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NOMENCLATURE

A	bulk area of cross-section	m^2 (ft^2)
c_{pi}	specific heat of component i	$kJ/kg\cdot C$ ($Btu/lb\cdot F$)
c_s	specific heat of rock matrix	$kJ/kg\cdot C$ ($Btu/lb\cdot F$)
C_{ia}	concentration of component i in phase α	mass frac
D	depth below sea level, positive downwards	m (ft)
D_{ia}	diffusion rate of i in phase α	m^2/s (ft^2/hr)
g	acceleration due to gravity	m/s^2
h_{ia}	enthalpy of component i in phase α	$kJ/kmole$ ($Btu/lbmole$)
k	absolute permeability in a given direction	m^2 ($1.127darcy$)
k_h	thermal conductivity in a given direction	$kW/m\cdot K$ ($Btu/day\cdot ft\cdot F$)
k_{ra}	relative permeability to α phase	frac
L_{vi}	latent heat of component i	kJ/kg (Btu/lb)
m_i^*	injection rate of component i	$kg/s\cdot m^3$ ($lb/day\cdot ft^3$)
M_i	molecular weight of component i	$kg/kmole$ ($lb/lbmole$)
M_α	molecular weight of α phase	$kg/kmole$ ($lb/lbmole$)
p	pressure	Pa ($psia$)
P_{cgo}	gas-oil capillary pressure	Pa ($psia$)
P_{cow}	oil-water capillary pressure	Pa ($psia$)
q_α^*	injection rate of α phase	$sm^3/m^3\cdot s$ ($STB/ft^3\cdot day$)
q_L^*	heat loss rate	$kJ/s\cdot m^3$ ($Btu/day\cdot ft^3$)
S_α	saturation of α phase	fraction pore volume
t	time	s (day)
v_α	phase pore velocity in a given direction	m/s (ft/day)
w	weighting factor for the upstream direction, 0 or 1	
x	coordinate	m (ft)
y	coordinate	m (ft)
z	coordinate	m (ft)
ϕ	porosity	fraction
ρ_α	density of the α phase	kg/m^3 (lb/ft^3)
μ_α	viscosity of the α phase	$Pa\cdot s$ ($centipoise$)

Chapter I

INTRODUCTION

Steam injection is currently responsible for the production of over one million barrels/day of heavy oil. There are two principal variations of steam injection: cyclic steam stimulation, which has been successful in Cold Lake oil sands formations, and is the only proven commercial heavy oil recovery method to-date for that area, and steamflooding, which has been highly successful in California, and is lately finding application in Saskatchewan. Eventually, some form of steamflooding may be applicable to Cold Lake reservoirs. This would, however, require the use of an additive with steam, which could be a gas, liquid, or a suitable foam, because steam alone cannot adequately mobilize the highly viscous oil. A suitable gas or liquid could lower oil viscosity under cold conditions, while a steam-based foam would improve sweep efficiency. The present study partly addresses this question.

Previous works dealing with steam injection simulation have not dealt with thermal upgrading, non-Newtonian oil rheology, and foam injection. These effects can be important. But the main purpose in this work is to show the incorporation of such effects in a steam injection simulator.

The principal field problem considered in this work is bottom water, which is a common problem in Alberta and Saskatchewan heavy oil formations. This can take many forms, ranging from an oil-water transition zone to 100% water, with full or partial communication with the overlying oil zone. These aspects are covered in this study. Bottom water heavy oil reservoirs may be exploited by special techniques, such as partial penetration, which was also considered in this work. Other strategies may involve injection of blocking agents such as foam. Steam is often injected into multiple oil zones from a single steam injection tubing. As a result, different zones take steam of different

qualities. This problem has not been examined in the literature thus far, and is considered in this work, using a wellbore simulator developed for this situation.

Chapter II

REVIEW OF THE LITERATURE

This chapter provides a review of the numerical simulators developed to date for steam injection studies. Various applications have been reported, mainly steamflooding. Cyclic steam simulations have been reported for simpler cases, e.g. effect of bottom water has been neglected. A number of steam simulators have been developed. Computational difficulties and the machine time requirements have limited the use of such simulators to relatively small grids, consisting of a few hundred, or fewer, blocks. A few investigators have examined the use of steam additives, mainly gases. The following survey is designed to highlight the main features of steam injection simulators in chronological order, and indicate the current status. Table 2.1 gives a summary of all the steam injection models, reported to date, indicating the main features of the models and the solution technique used.

Shutler (1968 and 1969) developed three phase, one- and two-dimensional models for steam injection. The mass balance equations for the three-phase (oleic, aqueous and vapour) flow were solved simultaneously, using Newtonian iteration for the steam condensation term, while the energy balance equation was solved separately by the non-iterative ADIP method. He allowed for the interphase mass transfer between water and steam phases, but considered the oil phase to be nonvolatile, and the hydrocarbon gas to be insoluble in the liquid phases.

Abdalla and Coats (1971) developed a three-phase (oil, water and gas), two-dimensional steam drive simulator. In this model the implicit-pressure, explicit saturation (IMPES) method was used. The model was relatively unstable in view of the approximate treatment of the nonlinearities.

Vinsome (1974) developed a three-phase (oil, water and steam) model for steam injection. A stabilized IMPES method was employed. While this was simpler than the implicit method, it provided second-order accuracy in the space derivatives, and large time

Table 2.1
MAIN FEATURES OF EXISTING THERMAL SIMULATORS

Model	Features	Solution Technique
Shutler (1968)	One-dimensional three-phase; included effects of three-phase relative permeability, capillary pressure.	Three-step solution technique for fluid flow, heat transfer and gas composition. Newtonian iteration employed for steam condensation term.
Shutler (1970)	Three-phase, two-dimensional steamflood model. Considers effect of gravity, reservoir heterogeneity, and non uniform initial fluid phase distribution.	Three-stage solution technique in each time step to obtain pressure and saturation, then temperature and finally gas composition.
Abdalla and Coats (1971)	Three-phase steamflood, dead oil	Explicit solution, unstable for most situations.
Coats et al. (1974)	Three-dimensional steam injection, three-phase. Dead oil, no solution gas.	Simultaneous solution of the mass and energy balances. Accounts for the effect of temperature on relative permeability.
Vinsome (1974)	Steam injection, two-dimensional.	IMPES. Iterates on steam condensation term. Very slow to converge.

Table 2.1 (continued)

MAIN FEATURES OF EXISTING THERMAL SIMULATORS

Model	Features	Solution Technique
Patel, Masliyah and Mathews (1977)	Steam injection, one-dimensional, radial.	Fully implicit solution of the pressure equation. Very stable.
Ferrer and Farouq Ali (1977)	Two-dimensional, three-phase, multicomponent thermal, compositional steam injection.	The mass and heat balance as well as compositional constraint equations were solved sequentially. Direct solution technique. Implicit pressure and explicit production rate. Slow to converge.
Weinstein et al. (1977)	One-dimensional, three-phase steam stimulation model.	Semi-implicit formulation. Sequential solution technique.
Coats (1978)	Three-dimensional steamflooding with distillation or solution gas.	Three-dimensional, highly implicit. Direct solution.
Crookston et al. (1978)	Thermal simulator one-dimensional, basically for fire flooding.	Direct solution technique, semi-implicit.

Table 2.1 (continued)
MAIN FEATURES OF EXISTING THERMAL SIMULATORS

Model	Features	Solution Technique
Abou Kasseem (1981)	Two-dimensional, three-phase steam model with solution gas. Nine-point difference scheme used.	Fully implicit treatment of all terms. Newtonian formulation, Gaussian elimination. Much computational work required.
Harding (1986)	One-dimensional, included nitrogen and CO ₂ as steam additives. Primarily to simulate laboratory steamfloods.	Highly implicit, direct solution method.

steps were utilized. A Runge-Kutta integration scheme was employed. It was claimed that this technique could be incorporated into the existing simulators to increase their efficiency.

Coats, George, Chu and Marcum (1974) developed a three-phase (oil, water and steam), three-dimensional simulator for steam injection. In their work, the mass and energy balance equations were solved simultaneously. They combined the water and steam equations in order to avoid iteration on the mass transfer condensation term. This model did not account for the distillation of oil.

Patel, Masliyah, and Mathews (1977) developed a one-dimensional radial steam model for three-phase (oil-water-gas) flow. They used a fully implicit scheme for the solution of the pressure equation. The model proved to be very stable for cyclic steam injection in oil sands.

Ferrer and Farouq Ali (1977) developed a three-phase compositional simulator that described the steam injection process in two dimensions. In this work, interphase mass and heat transfer were considered: thus, the oil composition changed during the steam injection process. The partial differential equations obtained for mass balance for each component, as well as the heat balance equation, were solved sequentially. The use of the model for cyclic steam stimulation and steamflooding was illustrated by several examples. The sensitivity of the model to the input parameters was also examined. This model indicated that steam distillation and gravity segregation are important factors in the steam injection processes.

Weinstein, Wheeler and Woods (1977) presented a three-phase, one-dimensional steam injection model to simulate a cyclic steam stimulation process. Interphase mass transfer was allowed between water and vapour, and oil and vapour. This model accounts for steam condensation, solution gas, and distillation effects. However, it does not consider gravity and capillary pressure, or temperature dependence of relative permeability. Also, this model accounts for two-dimensional heat transfer. An explicit mass transfer rate between the oil and vapour rather than a gas solubility factor suggested a new method of

treating solution gas and distillation effects. On the other hand, explicit treatment of this type can induce instability. The "sequential solution" scheme (Spillette, Hillstead and Stone, 1973) was used for solving the equations. Recent work has shown that such a procedure is less stable for steam injection simulations than implicit schemes. It was concluded that gas injection has a favourable effect on performance and that gas injection following steam is the best alternative.

Coats (1978) reported a three-dimensional, highly implicit numerical model for simulating steamflooding with distillation or solution gas. This model was an improvement over his previous works. He employed a direct solution technique to simultaneously solve three and four equations for the dead-oil and two-component oil cases, respectively. This model was more stable than the previous model, and required less computing time.

Crookston, Culham and Chen (1978) presented a semi-implicit numerical model for simulating thermal recovery processes. This model was used for one-dimensional *in situ* combustion studies. This three-phase, (oleic, aqueous, vapour), one-dimensional model included gravity (vertical runs) and capillary effects. Heat transfer by conduction, convection, and vapourization-condensation of both water and hydrocarbons were considered. A direct solution procedure was used to simultaneously solve the system of equations. This consisted of the alternating diagonal ordering Gaussian elimination scheme, which was utilized by Price and Coats (1974) as well.

Abou-Kassem (1981) developed a compositional steam injection model, suitable for two dimensions, with an implicit solution scheme. The main feature of this approach was in the use of a nine-point difference scheme instead of the five-point difference schemes used by other investigators. The nine-point formulation approximates flow in a plane much better, since the fluid is permitted to move in four additional directions. As a result, the grid orientation effects are minimized. Abou-Kassem showed that by using the nine-point scheme, the calculated saturation and temperature profiles were almost identical for parallel and diagonal grids. On the other hand, use of the nine-point scheme increases the

computational work enormously. Furthermore, a nine-point scheme becomes a twenty seven-point scheme in three dimensions. But this has not been tried as yet in view of the vast amount of computations needed on one hand, and numerical problems on the other. It was also shown that the method of two-point upstream relative permeabilities may not be valid for thermal simulators.

Harding (1986) developed a highly implicit thermal numerical simulator. This steam and gas injection model was designed to aid in the interpretation of one-dimensional laboratory experimental steamfloods. The model was employed for a variety of history matching runs and process sensitivity studies. Harding used a direct solution method in his simulator. The simulator was designed to represent special features, such as heat loss from a cylindrical core, heat loss from flanges, etc. The possibility of using nitrogen and CO₂ as steam additives were among the features incorporated into the numerical model. An important result of Harding's experimental-theoretical study was that the experimental results were unreliable due to very high heat loss. The numerical model pointed out the importance of heat loss. Thus, Harding's simulator proved to be a useful means for interpreting experimental data, indicating improvements to be made in the experimental design.

Steam Injection in the Presence of Bottom Water

Many heavy oil formations in Alberta and Saskatchewan as well as in California are characterized by a bottom water layer below the oil zone which is often in communication with it. This bottom layer may consist of merely a high water saturation zone, or a transition zone. In the following, this layer will be referred to as "bottom water". The extent of bottom water may be different for various reservoirs. It could be a thin sand, a few meters in thickness, or it may be an aquifer. The permeability of the water layer may be considerably different from that of the oil zone, if clays are present in the water-bearing sand. The presence of bottom water is likely to have two significant but competing effects

on thermal recovery processes. On one hand it could be a means of providing initial injectivity in the highly viscous oil sands. On the other hand, this zone may act as a heat sink, thereby, reducing the efficiency of heating the oil formation above.

In secondary and tertiary recovery methods, any injected fluid, which could be air, steam, solvent etc., will exhibit a tendency to migrate into the low resistance water sand. As a consequence, the displacement and sweep efficiencies will be poor. A variety of factors will determine the magnitude of such migration, such as oil viscosity, relative water sand thickness, injection rate, oil saturation in the water sand, relative permeability and well completion. Presence of a barrier between the oil and water zone will reduce the channeling tendency if the barrier extends to at least one-half the distance between injector and producer, and the bottom water is not active. Vertical permeability thus plays an important role and any shale breaks, silt zones, or other heterogeneities restricting vertical permeability at the base of the oil zone would be beneficial in the oil recovery performance.

Flow of heat from the water zone into the oil formation is a complicated situation to handle, if a hot fluid is injected. This situation will be still more complex if air is chosen as the injection fluid. In heavy oil thermal recovery processes, presence of a limited water zone could be an advantage, since it could serve as a means of initial injectivity.

Laboratory Experimentation

Several investigators have conducted laboratory experiments with bottom water steamfloods. Pursley (1974) carried out experiments with a scaled model to simulate a 1.25 acre pattern. The sand thickness was 140 ft, with 15% bottom water and oil viscosity was 100,000 cp. Upon injection of one pore volume of steam, 36% recovery was obtained. Steam override was observed; on the whole, it contacted a large proportion of the oil. The presence of bottom water was helpful in providing injectivity. This way the base of the oil zone was heated. Vertical permeability was also an important factor.

Ehrlich (1977) and Huygen and Lowry (1979) investigated the recovery process of a 5 million cp bitumen, with a bottom water layer. They observed that the heated bitumen was carried into the bottom water by the condensate.

Stegemeier, Laumbach and Volek (1980) as well as Prats (1977), and Doscher and Huang (1979) have reported experiments of bottom water steamfloods with low pressure scaled models. Prats conducted experiments for Peace River conditions (200,000 cp oil), with water-to-oil zone thickness ratios of 0.50, 0.25 and 0.10. The oil saturation in the water zone was 0.55-0.65. The operational procedure consisted of injecting steam into the water zone, pressurizing, and blowing down to raise the temperature of the overlying oil zone, and to carry the oil flowing by gravity into the water zone to the production wells with limited steam production. Different bottom water layers required a different optimal operating strategies. In all cases, oil-steam ratios were between 0.2 and 0.3.

Stegemeier et al. (1980) conducted experiments to simulate the Mt. Poso field, which has a water drive. They developed a successful operating technique for a typically marginal steamflood process. It consisted in injecting steam updip as the downdip wells watered-out. A line drive pattern was employed.

Doscher and Huang (1979) conducted steamflood experiments with a water zone. They observed that an increase in the steam injection rate delayed the oil production and decreased the oil-steam ratio. Gravity segregation of steam occurred at long times.

Farouq Ali, Abad and Snyder (1974, 1976) conducted a series of experimental studies, where bottom water simulation was carried out by means of a high permeability sand placed at the base of a vertical tar sand pack. Initially, steam was propagating at the base of the sand, advancing upward, and eventually the entire sand was heated, resulting in a recovery of almost 50%.

A few investigators have reported laboratory studies of *in situ* combustion in the presence of a water zone. Garon, Geisbrecht and Lowry (1980) carried out scaled model experiments using a 5 million cp bitumen. It was found that the combustion zone advanced

near the base of the oil zone, where there was no communication between the oil and water layers, as a result of preheating of the water layer by steam. In addition to a firefront advancing in the direction of air flow, a second front was observed which was moving slowly in the perpendicular direction. In cases where there was communication between the oil and water layers, the sweep was good, but the air-oil ratio was much higher (20,000 vs. 13,000 scf/bbl). Recovery was 11-12% in both cases.

Proctor (1986) carried out a series of scaled model experiments for steamflooding bottom water models under a variety of conditions. The operational strategies for thin reservoirs (20-40 ft), with the presence of bottom water were studied in this work. Oil viscosity of 1275 cp was employed in most cases. His studies included steamfloods in bottom water situations, gas injection in bottom water studies, where a small volume of gas was injected into the top of the pack followed by steam injection, and steamflood experiments employing horizontal wells. It was concluded that gas injection prior to steamflooding in reservoirs underlain with bottom water would create a high conductivity zone and divert steam from bottom water into the oil zone, hence improving oil recovery. Also, horizontal well runs exhibited a more efficient recovery.

Numerical Simulation of Bottom Water Reservoirs

Numerical simulations of cyclic steam injection for oil reservoirs underlain by water have been conducted by Bowen and Patel (1982) as well as Prats (1974). It was found that for the bottom water thickness-to-oil zone thickness ratios of about 0.2, the oil-steam ratio may fall in the acceptable range (0.1 to 0.2 bbl/bbl). Beyond that, the oil-steam ratio dropped rapidly. When this ratio reached 1.0, oil recovery became very low. These numbers were valid for a 50,000 cp oil, and would change for different operating parameters and conditions.

It was also reported that for thin water zones, a smaller slug is more efficient, since it has a tendency to create a heated zone rather than being dissipated into the water zone. It

appears that the performance was better for lower viscosity oils, but bottom water can have adverse effects for any oil viscosity. Study of saturation and temperature distributions in the developed simulators indicates steam channeling as well as oil migration into the water zone. These results were obtained from the first cycle. In subsequent cycles, however, the performance improves to some extent, and this is a result of radial heat conduction into the cold oil sand away from the hot zone.

Several simulations of steamflooding in the presence of bottom water were reported by Prats (1974). A study of this type for a 50,000 cp oil in a 50 ft sand with 10 ft of water shows that the oil-steam ratio initially tends to increase with cumulative steam injected, and then starts to decrease. Also, a strong rate dependence has been reported. Study of saturation and temperature shows that steam has a tendency to flow through the water zone, with heating of the overlying oil, causing the oil to gravitate to the water zone, from where it will be directed to the producing wells by hot water. Given enough time, steam will segregate by gravity in the oil zone, mobilizing the oil, and also channelling into the water zone. It was found that water zone thickness has a pronounced effect on the oil recovery, and for a water sand thickness equal to oil sand thickness, recovery was insignificant and virtually nil. Both sands had the same absolute permeability.

Crookston, Culham and Chen (1979) studied one example of a two-dimensional bottom water steamflood, which was a special case of a one-dimensional fireflood simulator.

Singh (1985) used a three component, implicit steamflood model. The mass and energy balance equations were solved simultaneously. The three components were: 1) heavy oil, 2) water and 3) an additive. The Peng-Robinson equation of state was used to obtain phase behaviour data. Capillary pressure was neglected. This model was designed to study oil recovery in the Athabasca tar sand area in Alberta, where the oil viscosity is over one million cp. The reservoir consisted of an oil zone 60 ft thick underlain by a water

zone with negligible oil saturation. This model was concerned with 1) the bottom water thickness, 2) steam injection rate, and 3) additive injection rate.

It was reported that application of a blocking agent would decrease the flow of steam in more conductive parts of the reservoir, thereby improving the oil-steam ratio. In the simulation, it was assumed that the blocking agent would reduce the permeability of the bottom water zone to zero. Two simulation runs were conducted to study the effect of a blocking agent on sweep efficiency, oil-steam ratio and oil formation heating. In these runs, steam was initially injected into the bottom water zone to mobilize the overlying oil and create adequate injectivity in the oil formation. Subsequently, the bottom water layer was assumed to be completely blocked, and steam injection was continued through the heated oil zone.

It was found that initially the injection of a blocking agent reduced the oil-steam ratio. It was postulated that by the time the oil above the bottom water was mobile enough to have injected steam flow through it, (the time at which the blocking agent was injected), a large amount of oil would be mobilized and flow downwards into the bottom water zone. Some of this oil was produced, while a considerable volume was trapped in the blocked water zone. This was responsible for the initially lower oil-steam ratio as compared with the cases where no blocking agent was employed. However, after some 50 additional days, higher oil-steam ratios were obtained, because the use of a blocking agent for a long enough time resulted in improved heating of the oil bearing-formation and a considerable amount of bitumen was produced from the oil zone.

It was concluded that a bottom water zone is helpful in improving injectivity, but too large a thickness of bottom water will delay response in oil production and will result in an increased amount of water production and, therefore, yield poorer sweep efficiency. It was also concluded that in a bottom water containing reservoir, a higher rate of steam injection results in considerable heat production together with fluid production, but very low rates cause considerable delay in oil production. It was also concluded that blocking agents can

improve sweep efficiency by providing efficient heating of the oil formations but they may result in oil entrapment in areas from which it cannot be produced.

Kasraie and Farouq Ali (1984, 1984, 1985, 1987) have discussed the problem of steamflooding and cyclic steaming in the presence of bottom water. For the oil viscosities and formation permeabilities considered, they concluded that heavy oil formations with bottom water not exceeding one-fifth of the oil zone thickness may be commercially amenable to steam injection.

Chapter III

STATEMENT OF THE PROBLEM

Although a number of steam injection simulators have been developed, as reviewed in Chapter II, a number of important features of steam injection processes have not been considered. It is the purpose of this work to develop steam injection simulators in order to examine the following problems:

1. To investigate the features of thermal upgrading, non-Newtonian oil rheology, and steam-foam flow in a three-dimensional, multicomponent simulator, and determine the effects of these features in selected steamflood simulations, and to examine the effect of gas injection with steam on cyclic steaming response.
2. To examine the effect of a bottom water zone on steamflooding and cyclic steam stimulation performance. In this regard, the effects of partial penetration, relative water zone thickness, oil and water zone absolute permeabilities and vertical permeability are to be studied.
3. To simulate a scaled laboratory steamflood, and determine the extent of necessary adjustments to field relative permeabilities for obtaining a reasonable match.
4. To develop a wellbore model for determining the effect of multiple offtake in a steam injection well on wellbore steam quality and pressure. Then to use the steam quality and pressure, as functions of time, in steamflood simulations to determine the effect on oil recovery and other parameters.

DEVELOPMENT OF THE MATHEMATICAL MODEL

Introduction

In this research, two three-phase, multicomponent thermal simulators for steam injection were developed. These consist of (i) a three-dimensional, two-component simulator, and (ii) a two-dimensional, four-component simulator. The model development given below is for a generalized three-dimensional, multicomponent, three-phase steam injection simulator, all the groundwork for which was accomplished. The aforesaid simulators employed similar development, being subsets. The simulators were employed for a variety of steam injection situations, including foam flow, thermal upgrading, use of additives, and non-Newtonian oil rheology. In addition, a wellbore simulator was developed, with the feature of fluid flow regime changes, which was used to examine steam quality variations when steam is injected into two separate layers from a single tubing. The aforementioned are new features, not reported before.

The three-dimensional, three-phase, multicomponent simulator employs a fully implicit formulation. Newtonian iteration is used to solve the resulting nonlinear difference equations. The algebraic equations for the grid have a block band matrix structure, with a 6×6 block size. In the following section, the model formulation, the finite difference approximations, derivation of the Jacobians, and the overall solution scheme will be discussed. SI units are used in the following development.

Simulator Equations

Assumptions

This thermal model represents non-isothermal flow of three phases (oleic, aqueous, and vapour) in three dimensions. Each phase can consist of as many as five components, and interphase mass transfer of all components is allowed. In the mass balance equation, molecular diffusion within each phase is allowed for, however instantaneous equilibrium is assumed between phases. Thermal equilibrium is also assumed between phases, as well as between the fluids and the rock matrix. Heat transfer to the impermeable, adjacent formations above and below is governed by the diffusivity equation. The composition of a particular phase is determined by the K-values. Mild thermal cracking of the heavy hydrocarbon is allowed to occur, and is taken to be a function of temperature and time, based upon published laboratory data. It is assumed that the volume of carbon formed as a result is negligible.

While heat loss to the formations above and below is allowed, lateral heat flow is assumed to be zero. In the energy balance, the terms for kinetic energy, work done by viscous forces, and work done by body forces have been neglected, being small.

As one example, the components are: (1) non-volatile hydrocarbon, (2) water, (3) surfactant, (4) non-condensable gas, and (5) electrolyte (salt). Other components may be employed, as needed, so long as the respective K-values are available.

The three-phase relative permeabilities to oil, water, and gas were calculated by Naar-Wygal-Henderson and Stone methods, as discussed below. In some cases, the relative permeabilities were made temperature-dependent.

Mass Balance for a Component

In order to derive the mass balance for component i , consider a volume element of sides $\Delta x, \Delta y, \Delta z$, with flow of the three phases into and out of the element in the x -, y -, and z -directions. Molecular diffusion within each phase is allowed for. Instantaneous phase equilibrium is assumed.

Diffusion of component i is described by Fick's law of diffusion. For example, the mass diffusion rate of component i in the x -direction in the oleic phase is given by

$$m_{i_o} = -AD_{i_o} \frac{\partial \rho_o C_{i_o}}{\partial x}, \quad (4.1)$$

where m_i is the mass diffusion rate of component i in kg/s, A is total area in m^2 , D_{i_o} is the rate of diffusion of component i in the oleic phase in m^2/s , ρ_o is the oleic phase density in kg/m^3 , and C_{i_o} is the mass concentration of component i in the oleic phase.

The mass balance on component i for flow in all three directions can be written as follows:

$$\text{Net mass throughput} + \text{Net mass change} = 0$$

For example, the mass balance for one dimensional flow gives the following equation:

$$\begin{aligned} & [(\rho_o q_o C_{i_o})|_{x+\Delta x} + (\rho_w q_w C_{i_w})|_{x+\Delta x} + (\rho_g q_g C_{i_g})|_{x+\Delta x} \\ & - (\rho_o q_o C_{i_o})|_x - (\rho_w q_w C_{i_w})|_x - (\rho_g q_g C_{i_g})|_x + m_{i_o}|_{x+\Delta x} - m_{i_o}|_x + m_{i_w}|_{x+\Delta x} \\ & - m_{i_w}|_x + m_{i_g}|_{x+\Delta x} - m_{i_g}|_x - m_{i_o}^* - m_{i_w}^*] \Delta t \\ & + [(\phi S_o \rho_o C_{i_o})|_{t+\Delta t} + (\phi S_w \rho_w C_{i_w})|_{t+\Delta t} + (\phi S_g \rho_g C_{i_g})|_{t+\Delta t} \end{aligned}$$

$$-(\phi S_o \rho_o C_{i_o}) \Big|_i - (\phi S_w \rho_w C_{i_w}) \Big|_i - (\phi S_g \rho_g C_{i_g}) \Big|_i \cdot A \Delta x = 0. \quad (4.2)$$

The q-terms are replaced by velocities, using Darcy's equation for multiphase flow. Rearranging, and taking the limits of Δx (and similarly, Δy and Δz , for three dimensions) and Δt to zero, the following equation results:

$$\begin{aligned} & \nabla \cdot \left(\frac{k k_{ro} \rho_o C_{i_o}}{\mu_o} \nabla \Phi_o \right) + \nabla \cdot \left(\frac{k k_{rw} \rho_w C_{i_w}}{\mu_w} \nabla \Phi_w \right) + \nabla \cdot \left(\frac{k k_{rg} \rho_g C_{i_g}}{\mu_g} \nabla \Phi_g \right) \\ & + \nabla \cdot (D_{i_o} \nabla (\rho_o C_{i_o})) + \nabla \cdot (D_{i_w} \nabla (\rho_w C_{i_w})) + \nabla \cdot (D_{i_g} \nabla (\rho_g C_{i_g})) + m_{i^*} + m_{si^*} + \sum_{j=1}^J P_{ji} \\ & = \frac{\partial}{\partial t} (\phi S_o \rho_o C_{i_o} + \phi S_w \rho_w C_{i_w} + \phi S_g \rho_g C_{i_g}), \end{aligned} \quad (4.3)$$

where P_{ji} is the rate of generation of component i from the j th reaction, with J reactions taking place. The remaining symbols are defined in the Nomenclature.

At this stage, the Φ s are replaced by phase pressures as follows

$$\Phi_o = p_o - \rho_o g D, \quad (4.4)$$

where D is depth below sea level, in m. Next, the capillary pressure relations are used to reduce the water and gas phase pressures to oil pressure, which is taken to be the principal unknown:

$$P_{cow} = p_o - p_w, \quad (4.5)$$

$$P_{cgo} = p_g - p_o. \quad (4.6)$$

The final form of the mass balance equation for component i is:

$$\begin{aligned} & \nabla \cdot \left[\left(\frac{k k_{ro} \rho_o C_{i_o}}{\mu_o} + \frac{k k_{rw} \rho_w C_{i_o}}{\mu_w f_{iow}} + \frac{k k_{rg} \rho_g C_{i_o}}{\mu_g f_{iog}} \right) \nabla p_o \right] \\ & - \nabla \cdot \left[\left(\frac{k k_{ro} \rho_o C_{i_o}}{\mu_o} \rho_o g + \frac{k k_{rw} \rho_w C_{i_o}}{\mu_w f_{iow}} \rho_w g + \frac{k k_{rg} \rho_g C_{i_o}}{\mu_g f_{iog}} \rho_g g \right) \nabla D \right] \\ & - \nabla \cdot \left(\frac{k k_{rw} \rho_w C_{i_o}}{\mu_w f_{iow}} \nabla P_{cow} \right) + \nabla \cdot \left(\frac{k k_{rg} \rho_g C_{i_o}}{\mu_g f_{iog}} \nabla P_{cgo} \right) \end{aligned}$$

$$\begin{aligned}
& + \nabla \cdot (D_{i_o} \nabla (\rho_o C_{i_o})) + \nabla \cdot (D_{i_w} \nabla (\rho_w \frac{C_{i_o}}{f_{iow}})) + \nabla \cdot (D_{i_g} \nabla (\rho_g \frac{C_{i_o}}{f_{iog}})) + m_{i^*} + m_{ii^*} - \sum_{j=1}^J P_{ji} \\
& = \frac{\partial}{\partial t} (\phi(1 - S_w - S_g) \rho_o C_{i_o} + \phi S_w \rho_w \frac{C_{i_o}}{f_{iow}} + \phi S_g \rho_g \frac{C_{i_o}}{f_{iog}}).
\end{aligned} \tag{4.7}$$

The finite difference approximation to this equation is discussed in a subsequent section.

Heat Balance

The heat balance equation takes into account heat conduction within the reservoir in all three directions. Besides, it considers heat convection due to the flow of the oleic, aqueous, and vapour phases. In the general case, each phase contains five components, as mentioned previously. The heat balance also includes the feature of heat transport due to the molecular diffusion of the components. Heat loss to the overlying and underlying adjacent formations is allowed, assuming conductive transfer only because these boundaries are impermeable to flow. Lateral heat loss is neglected in the present model, because we are considering elements of symmetry, with no-flow boundaries. Where this is not the case, it is possible to include a heat loss term to account for such a loss. In practice, because the heat flow in the lateral direction is confined to the formation, it is usually not considered a loss.

As for mass balance, consider flow of heat in the x -direction; a similar treatment could be used for the y - and z -directions. The heat balance can be written as

Net heat throughput in time Δt = Net change in heat content

The heat flow consists of conduction, convection, and that due to molecular diffusion. Writing the heat balance for an element with dimensions $\Delta x, \Delta y$, and Δz , we have

$$\begin{aligned}
& [q_{cond_{x+\Delta x}} - q_{cond_x} + q_{cond_{y+\Delta y}} - q_{cond_y} + q_{cond_{z+\Delta z}} - q_{cond_z}] \Delta t \\
& + [q_{conv_{x+\Delta x}} - q_{conv_x} + q_{conv_{y+\Delta y}} - q_{conv_y} + q_{conv_{z+\Delta z}} - q_{conv_z}] \Delta t \\
& + [q_{diff_{x+\Delta x}} - q_{diff_x} + q_{diff_{y+\Delta y}} - q_{diff_y} + q_{diff_{z+\Delta z}} - q_{diff_z}] \Delta t \\
& + [\frac{q_o \rho_o}{M_o} \sum_i x_{i_o} h_{i_o,i,j,k}^{n+1} + \frac{q_w \rho_w}{M_w} \sum_i x_{i_w} h_{i_w,i,j,k}^{n+1} + \frac{q_g \rho_g}{M_g} \sum_i x_{i_g} h_{i_g,i,j,k}^{n+1} - q_L^* + r_H^*] \Delta t \\
& + \Delta x \Delta y \Delta z \{ (1 - \phi) \frac{\rho_s}{M_s} h_s + \frac{\phi \rho_o S_o}{M_o} \sum_i x_{i_o} h_{i_o} + \frac{\phi \rho_w S_w}{M_w} \sum_i x_{i_w} h_{i_w} + \frac{\phi \rho_g S_g}{M_g} \sum_i x_{i_g} h_{i_g} \}_{t+\Delta t} \\
& - \Delta x \Delta y \Delta z \{ (1 - \phi) \frac{\rho_s}{M_s} h_s + \frac{\phi \rho_o S_o}{M_o} \sum_i x_{i_o} h_{i_o} + \frac{\phi \rho_w S_w}{M_w} \sum_i x_{i_w} h_{i_w} + \frac{\phi \rho_g S_g}{M_g} \sum_i x_{i_g} h_{i_g} \}_t = 0,
\end{aligned} \tag{4.8}$$

where q_{cond_x} , for example, is the heat conducted in the x -direction, and is given by

$$q_{cond_x} = -Ak_{hx} \frac{\partial T}{\partial x} \quad (4.9)$$

Similarly, q_{conv_x} is heat convection in the x -direction, given by

$$q_{conv_x} = \frac{v_o \rho_o}{M_o} \sum_i x_{i_o} h_{i_o} \quad (4.10)$$

In the same way,

$$q_{diff_x} = m_i h_{i_{ox}}, \quad (4.11)$$

where m_i is given by Eq.(4.1). Other symbols are defined in the Nomenclature; q^*_L is the heat loss rate to the adjacent formations, in kJ/s-m^3 , and r_H is the heat of any reactions occurring, in the same units.

Dividing Eq.(4.8) by $\Delta x \Delta y \Delta z \Delta t$, and taking the limit for $\Delta x, \Delta y, \Delta z, \Delta t \rightarrow 0$, the following equation is obtained:

$$\begin{aligned} & \nabla \cdot (k_h \nabla T) - \nabla \left[\frac{v_o \rho_o}{M_o} \sum_i x_{i_o} h_{i_o} + \frac{v_w \rho_w}{M_w} \sum_i x_{i_w} h_{i_w} + \frac{v_g \rho_g}{M_g} \sum_i x_{i_g} h_{i_g} \right] \\ & - \nabla \cdot \sum_i [J_{i_o} h_{i_o} + J_{i_w} h_{i_w} + J_{i_g} h_{i_g}] - q_L^* + r_H^* \\ & + \frac{q_o^* \rho_o}{M_o} \sum_i x_{i_o} h_{i_o, j, k}^{n+1} + \frac{q_w^* \rho_w}{M_w} \sum_i x_{i_w} h_{i_w, j, k}^{n+1} + \frac{q_g^* \rho_g}{M_g} \sum_i x_{i_g} h_{i_g, j, k}^{n+1} \\ & = \frac{\partial}{\partial t} \left[(1 - \phi) \frac{\rho_s}{M_s} h_s + \frac{\phi \rho_o S_o}{M_o} \sum_i x_{i_o} h_{i_o} + \frac{\phi \rho_w S_w}{M_w} \sum_i x_{i_w} h_{i_w} + \frac{\phi \rho_g S_g}{M_g} \sum_i x_{i_g} h_{i_g} \right], \end{aligned} \quad (4.12)$$

The above equation is adequate for all practical purposes; however, for completeness, the following terms should be added to the right side of the above equation:

$$\begin{aligned} & \frac{\partial}{\partial t} \left[\frac{1}{2Jg_c} \left(\frac{\rho_o v_o^2}{M_o} + \frac{\rho_w v_w^2}{M_w} + \frac{\rho_g v_g^2}{M_g} \right) \right] \\ & - \frac{1}{2Jg_c} \nabla \cdot \left(\frac{\rho_o v_o}{M_o} v_o^2 + \frac{\rho_w v_w}{M_w} v_w^2 + \frac{\rho_g v_g}{M_g} v_g^2 \right) \\ & - \nabla \cdot (\tau_o v_o + \tau_w v_w + \tau_g v_g) \end{aligned}$$

The above terms are negligibly small under most conditions. The above groups of terms respectively represent the kinetic energy, the body force work, kinetic energy again, and work done by viscous forces. Before expanding Eq.(4.12), the following substitutions are made:

$$h_{i_o} = c_p(T - T_R)M_i, \quad (4.13)$$

and

$$h_{i_g} = (c_p(T - T_R) + L_v)M_i, \quad (4.14)$$

where the units of each term are kJ/kmole. The final form of Eq.(4.12) before discretization by finite differences is as follows:

$$\begin{aligned} & \nabla \cdot (k_h \nabla T) - \nabla(\rho_o v_o T \sum_i c_p C_{i_o} + \rho_w v_w T \sum_i c_p C_{i_w} + \rho_g v_g \sum_i (c_p T + L_v) C_{i_g}) \\ & - \nabla \cdot (\rho_o \sum_i c_p T D_{i_o} \nabla C_{i_o} + \rho_w \sum_i c_p T D_{i_w} \nabla C_{i_w} + \rho_g \sum_i (c_p T + L_v) D_{i_g} \nabla C_{i_g}) \\ & - qL^* + rH^* + \frac{q_o^* \rho_o}{M_o} \sum_i x_{i_o} h_{i_o,j,k}^{n+1} + \frac{q_w^* \rho_w}{M_w} \sum_i x_{i_w} h_{i_w,j,k}^{n+1} + \frac{q_g^* \rho_g}{M_g} \sum_i x_{i_g} h_{i_g,j,k}^{n+1} \\ & = \frac{\partial}{\partial t} [(1 - \phi) \frac{\rho_o}{M_o} c_p T + \phi \rho_o S_o \sum_i c_p T C_{i_o} + \phi \rho_w S_w \sum_i c_p T C_{i_w} + \phi \rho_g S_g \sum_i (c_p T + L_v) C_{i_g}]. \end{aligned} \quad (4.15)$$

Formulation of the Problem

We shall now state the multiphase, multicomponent flow problem completely for a block, containing a well (source/sink). Consider a system of N components in three phases. The unknowns are as follows:

p_o =oleic phase pressure

p_w =aqueous phase pressure

p_g =vapour phase pressure

S_o =oleic phase saturation

S_w =aqueous phase saturation

S_g =vapour phase saturation

T =temperature

C_{i_o} =mass fraction of component i in the oleic phase ($i = 1, 2, \dots, N$)

C_{i_w} =mass fraction of component i in the aqueous phase ($i = 1, 2, \dots, N$)

C_{i_g} =mass fraction of component i in the vapour phase ($i = 1, 2, \dots, N$)

q_o^* =oleic phase injection rate (+) or production rate (-)

q_w^* = aqueous phase injection rate (+) or production rate (-)

q_g^* = vapour phase injection rate (+) or production rate (-)

Thus the total number of unknowns is $3N + 10$ in the most general case. The equations to be solved are as follows:

Mass balance for component i , Eq.(4.7), $(i = 1, 2, \dots, N)$ N equations,

Energy balance, Eq.(4.15) 1 equation,

Saturation constraint $S_o + S_w + S_g = 1$ 1 equation,

Capillary pressure relationships $P_{cow} = p_o - p_w$, 1 equation,

$P_{cgo} = p_g - p_o$ 1 equation,

Mole fraction constraints $\sum_{i=1}^N x_{io} = 1$ 1 equation,

$\sum_{i=1}^N x_{iw} = 1$ 1 equation,

$\sum_{i=1}^N x_{ig} = 1$ 1 equation,

K-values for the oleic/aqueous and oleic/vapour phases

$K_{iow} = \frac{x_{io}}{x_{iw}}$ $(i = 1, 2, \dots, N)$ N equations,

$K_{iog} = \frac{x_{ig}}{x_{io}}$ $(i = 1, 2, \dots, N)$ N equations.

Well flow rate relationships

$$q_w^* = \left(\frac{k_{rw} \rho_w \rho_{osc} \mu_o}{k_{ro} \rho_o \rho_{wsc} \mu_w} \frac{\partial \Phi_o}{\partial r} \right) q_o^* \quad 1 \text{ equation}$$

$$q_g^* = \left(\frac{k_{rg} \rho_g \rho_{osc} \mu_o}{k_{ro} \rho_o \rho_{gsc} \mu_g} \frac{\partial \Phi_g}{\partial r} \right) q_o^* \quad 1 \text{ equation}$$

The oil rate is specified, or one of the other rates, or the total rate could be specified. The total number of equations is thus seen to be $3N + 10$, same as the total number of unknowns. The problem is properly formulated, given appropriate boundary and initial conditions. It should be noted that in this work, mass fractions of the components i , i.e. C_{io} , C_{iw} , and C_{ig} were used in place of mole fractions. These are related to the mole fractions by equations of the following type

$$C_{io} = \frac{x_{io} M_i}{M_o}$$

Boundary and Initial Conditions

In this model, the reservoir boundaries are assumed to be closed to flow of fluids, flow of heat (except at the top and base of the formation), and diffusional transfer. Each of the dependent variables is a function of x, y, z , and t , e.g. $p_o = p_o(x, y, z, t)$. The boundary conditions can be stated as follows:

$$\left. \frac{\partial p_o}{\partial x} \right|_{C_x} = 0,$$

$$\left. \frac{\partial p_o}{\partial y} \right|_{C_y} = 0,$$

$$\left. \frac{\partial p_o}{\partial z} \right|_{C_z} = 0,$$

$$\left. \frac{\partial T}{\partial x} \right|_{C_x} = 0,$$

$$\left. \frac{\partial T}{\partial y} \right|_{C_y} = 0,$$

$$\left. \frac{\partial T}{\partial z} \right|_b \neq 0,$$

$$\left. \frac{\partial C_{1o}}{\partial x} \right|_{C_x} = 0,$$

$$\left. \frac{\partial C_{1o}}{\partial y} \right|_{C_y} = 0,$$

$$\left. \frac{\partial C_{1o}}{\partial z} \right|_{C_z} = 0,$$

$$\left. \frac{\partial C_{2o}}{\partial x} \right|_{C_x} = 0,$$

$$\left. \frac{\partial C_{2o}}{\partial y} \right|_{C_y} = 0,$$

$$\left. \frac{\partial C_{2o}}{\partial z} \right|_{C_z} = 0,$$

where C is the entire exterior surface of the reservoir normal to the x, y , and z directions, and b is a subset consisting of the top and the base of the reservoir.

Initial conditions can be stated as follows:

$$p_o(x, y, z, 0) = p_{oi},$$

$$S_w(x, y, z, 0) = S_{wi},$$

$$S_g(x, y, z, 0) = S_{gi},$$

$$T(x, y, z, 0) = T_i,$$

$$C_{10}(x, y, z, 0) = C_{10},$$

$$C_{20}(x, y, z, 0) = C_{20},$$

$$C_{30}(x, y, z, 0) = C_{30},$$

$$C_{40}(x, y, z, 0) = C_{40},$$

$$C_{50}(x, y, z, 0) = C_{50}.$$

The initial water and gas pressure values are based upon the capillary pressure and temperature data. In the case of the injection and production wells, the boundary and initial conditions are given by the source-sink terms, as discussed previously. It is important to note that the initial mass fractions of all components in each phase must add to 1 separately. This is done by carrying out an initial flash equilibrium calculation for the mixture.

Finite Difference Approximations

Component Mass Balance

The partial differential equations obtained for each component as well as the heat balance equation were discretized for the fully implicit formulation, i.e. all transmissibilities, nonlinear coefficients, and source/sink terms (mass as well as heat terms) were taken at time level $n + 1$. All variable parts of fluid and heat transmissibilities were taken at the upstream conditions.

The mass balance equation for component i can be expressed as

$$F_{i,j,k} = 0, \quad (4.15)$$

where the single i refers to a particular component ($i = 1, 2, \dots, 5$), and the subscript (i, j, k) refers to a particular block in a three-dimensional grid, and F is given by

$$\begin{aligned} F_{i,j,k} = & T_x \Big|_{i+\frac{1}{2},j,k}^{n+1} p_{oi,j,k}^{n+1} + T_x \Big|_{i-\frac{1}{2},j,k}^{n+1} p_{oi-1,j,k}^{n+1} + T_y \Big|_{i,j+\frac{1}{2},k}^{n+1} p_{oi,j+1,k}^{n+1} \\ & + T_y \Big|_{i,j-\frac{1}{2},k}^{n+1} p_{oi,j-1,k}^{n+1} + T_z \Big|_{i,j,k+\frac{1}{2}}^{n+1} p_{oi,j,k+1}^{n+1} + T_z \Big|_{i,j,k-\frac{1}{2}}^{n+1} p_{oi,j,k-1}^{n+1} \\ & - (T_x \Big|_{i+\frac{1}{2},j,k}^{n+1} + T_x \Big|_{i-\frac{1}{2},j,k}^{n+1} + T_y \Big|_{i,j+\frac{1}{2},k}^{n+1} + T_y \Big|_{i,j-\frac{1}{2},k}^{n+1} + T_z \Big|_{i,j,k+\frac{1}{2}}^{n+1} + T_z \Big|_{i,j,k-\frac{1}{2}}^{n+1}) p_{oi,j,k}^{n+1} \end{aligned}$$

$$\begin{aligned}
& -T_{gxx}|_{i+\frac{1}{2},j,k}^{n+1} D_{i+1,j,k}^{n+1} - T_{gxx}|_{i-\frac{1}{2},j,k}^{n+1} D_{i-1,j,k}^{n+1} - T_{gxy}|_{i,j+\frac{1}{2},k}^{n+1} D_{i,j+1,k}^{n+1} \\
& -T_{gxy}|_{i,j-\frac{1}{2},k}^{n+1} D_{i,j-1,k}^{n+1} - T_{gzz}|_{i,j,k+\frac{1}{2}}^{n+1} D_{i,j,k+1}^{n+1} - T_{gzz}|_{i,j,k-\frac{1}{2}}^{n+1} D_{i,j,k-1}^{n+1} \\
& -(T_{gxx}|_{i+\frac{1}{2},j,k}^{n+1} + T_{gxx}|_{i-\frac{1}{2},j,k}^{n+1} + T_{gxy}|_{i,j+\frac{1}{2},k}^{n+1} + T_{gxy}|_{i,j-\frac{1}{2},k}^{n+1} - T_{gzz}|_{i,j,k+\frac{1}{2}}^{n+1} - T_{gzz}|_{i,j,k-\frac{1}{2}}^{n+1}) D_{i,j,k}^{n+1} \\
& -T_{wx}|_{i+\frac{1}{2},j,k}^{n+1} P_{cow,i+1,j,k}^{n+1} - T_{wx}|_{i-\frac{1}{2},j,k}^{n+1} P_{cow,i-1,j,k}^{n+1} - T_{wy}|_{i,j+\frac{1}{2},k}^{n+1} P_{cow,i,j+1,k}^{n+1} \\
& -T_{wy}|_{i,j-\frac{1}{2},k}^{n+1} P_{cow,i,j-1,k}^{n+1} - T_{wz}|_{i,j,k+\frac{1}{2}}^{n+1} P_{cow,i,j,k+1}^{n+1} - T_{wz}|_{i,j,k-\frac{1}{2}}^{n+1} P_{cow,i,j,k-1}^{n+1} \\
& +(T_{wx}|_{i+\frac{1}{2},j,k}^{n+1} + T_{wx}|_{i-\frac{1}{2},j,k}^{n+1} + T_{wy}|_{i,j+\frac{1}{2},k}^{n+1} + T_{wy}|_{i,j-\frac{1}{2},k}^{n+1} + T_{wz}|_{i,j,k+\frac{1}{2}}^{n+1} + T_{wz}|_{i,j,k-\frac{1}{2}}^{n+1}) P_{cow,i,j,k}^{n+1} \\
& +T_{gx}|_{i+\frac{1}{2},j,k}^{n+1} P_{cgo,i+1,j,k}^{n+1} + T_{gx}|_{i-\frac{1}{2},j,k}^{n+1} P_{cgo,i-1,j,k}^{n+1} + T_{gy}|_{i,j+\frac{1}{2},k}^{n+1} P_{cgo,i,j+1,k}^{n+1} \\
& +T_{gy}|_{i,j-\frac{1}{2},k}^{n+1} P_{cgo,i,j-1,k}^{n+1} + T_{gz}|_{i,j,k+\frac{1}{2}}^{n+1} P_{cgo,i,j,k+1}^{n+1} + T_{gz}|_{i,j,k-\frac{1}{2}}^{n+1} P_{cgo,i,j,k-1}^{n+1} \\
& +(T_{gx}|_{i+\frac{1}{2},j,k}^{n+1} + T_{gx}|_{i-\frac{1}{2},j,k}^{n+1} + T_{gy}|_{i,j+\frac{1}{2},k}^{n+1} + T_{gy}|_{i,j-\frac{1}{2},k}^{n+1} + T_{gz}|_{i,j,k+\frac{1}{2}}^{n+1} + T_{gz}|_{i,j,k-\frac{1}{2}}^{n+1}) P_{cgo,i,j,k}^{n+1} \\
& +\frac{A_x D_{io}}{\Delta x}|_{i+\frac{1}{2},j,k}^{n+1} (\rho_o C_{io})_{i+1,j,k}^{n+1} + \frac{A_x D_{io}}{\Delta x}|_{i-\frac{1}{2},j,k}^{n+1} (\rho_o C_{io})_{i-1,j,k}^{n+1} + \frac{A_y D_{io}}{\Delta y}|_{i,j+\frac{1}{2},k}^{n+1} (\rho_o C_{io})_{i,j+1,k}^{n+1} \\
& +\frac{A_y D_{io}}{\Delta y}|_{i,j-\frac{1}{2},k}^{n+1} (\rho_o C_{io})_{i,j-1,k}^{n+1} + \frac{A_z D_{io}}{\Delta z}|_{i,j,k+\frac{1}{2}}^{n+1} (\rho_o C_{io})_{i,j,k+1}^{n+1} + \frac{A_z D_{io}}{\Delta z}|_{i,j,k-\frac{1}{2}}^{n+1} (\rho_o C_{io})_{i,j,k-1}^{n+1} \\
& -(\frac{A_x D_{io}}{\Delta x}|_{i+\frac{1}{2},j,k}^{n+1} + \frac{A_x D_{io}}{\Delta x}|_{i-\frac{1}{2},j,k}^{n+1} + \frac{A_y D_{io}}{\Delta y}|_{i,j+\frac{1}{2},k}^{n+1} + \frac{A_y D_{io}}{\Delta y}|_{i,j-\frac{1}{2},k}^{n+1} + \frac{A_z D_{io}}{\Delta z}|_{i,j,k+\frac{1}{2}}^{n+1} + \frac{A_z D_{io}}{\Delta z}|_{i,j,k-\frac{1}{2}}^{n+1}) (\rho_o C_{io})_{i,j,k}^{n+1} \\
& +\frac{A_x D_{iw}}{\Delta x}|_{i+\frac{1}{2},j,k}^{n+1} (\frac{\rho_o C_{io}}{f_{iow}})_{i+1,j,k}^{n+1} + \frac{A_x D_{iw}}{\Delta x}|_{i-\frac{1}{2},j,k}^{n+1} (\frac{\rho_o C_{io}}{f_{iow}})_{i-1,j,k}^{n+1} + \frac{A_y D_{iw}}{\Delta y}|_{i,j+\frac{1}{2},k}^{n+1} (\frac{\rho_o C_{io}}{f_{iow}})_{i,j+1,k}^{n+1} \\
& +\frac{A_y D_{iw}}{\Delta y}|_{i,j-\frac{1}{2},k}^{n+1} (\frac{\rho_o C_{io}}{f_{iow}})_{i,j-1,k}^{n+1} + \frac{A_z D_{iw}}{\Delta z}|_{i,j,k+\frac{1}{2}}^{n+1} (\frac{\rho_o C_{io}}{f_{iow}})_{i,j,k+1}^{n+1} + \frac{A_z D_{iw}}{\Delta z}|_{i,j,k-\frac{1}{2}}^{n+1} (\frac{\rho_o C_{io}}{f_{iow}})_{i,j,k-1}^{n+1} \\
& -(\frac{A_x D_{iw}}{\Delta x}|_{i+\frac{1}{2},j,k}^{n+1} + \frac{A_x D_{iw}}{\Delta x}|_{i-\frac{1}{2},j,k}^{n+1} + \frac{A_y D_{iw}}{\Delta y}|_{i,j+\frac{1}{2},k}^{n+1} + \frac{A_y D_{iw}}{\Delta y}|_{i,j-\frac{1}{2},k}^{n+1} + \frac{A_z D_{iw}}{\Delta z}|_{i,j,k+\frac{1}{2}}^{n+1} + \frac{A_z D_{iw}}{\Delta z}|_{i,j,k-\frac{1}{2}}^{n+1}) (\frac{\rho_o C_{io}}{f_{iow}})_{i,j,k}^{n+1} \\
& +\frac{A_x D_{ig}}{\Delta x}|_{i+\frac{1}{2},j,k}^{n+1} (\frac{\rho_g C_{io}}{f_{iog}})_{i+1,j,k}^{n+1} + \frac{A_x D_{ig}}{\Delta x}|_{i-\frac{1}{2},j,k}^{n+1} (\frac{\rho_g C_{io}}{f_{iog}})_{i-1,j,k}^{n+1} + \frac{A_y D_{ig}}{\Delta y}|_{i,j+\frac{1}{2},k}^{n+1} (\frac{\rho_g C_{io}}{f_{iog}})_{i,j+1,k}^{n+1} \\
& +\frac{A_y D_{ig}}{\Delta y}|_{i,j-\frac{1}{2},k}^{n+1} (\frac{\rho_g C_{io}}{f_{iog}})_{i,j-1,k}^{n+1} + \frac{A_z D_{ig}}{\Delta z}|_{i,j,k+\frac{1}{2}}^{n+1} (\frac{\rho_g C_{io}}{f_{iog}})_{i,j,k+1}^{n+1} + \frac{A_z D_{ig}}{\Delta z}|_{i,j,k-\frac{1}{2}}^{n+1} (\frac{\rho_g C_{io}}{f_{iog}})_{i,j,k-1}^{n+1} \\
& -(\frac{A_x D_{ig}}{\Delta x}|_{i+\frac{1}{2},j,k}^{n+1} + \frac{A_x D_{ig}}{\Delta x}|_{i-\frac{1}{2},j,k}^{n+1} + \frac{A_y D_{ig}}{\Delta y}|_{i,j+\frac{1}{2},k}^{n+1} + \frac{A_y D_{ig}}{\Delta y}|_{i,j-\frac{1}{2},k}^{n+1} + \frac{A_z D_{ig}}{\Delta z}|_{i,j,k+\frac{1}{2}}^{n+1} + \frac{A_z D_{ig}}{\Delta z}|_{i,j,k-\frac{1}{2}}^{n+1}) (\frac{\rho_g C_{io}}{f_{iog}})_{i,j,k}^{n+1} \\
& +V_{b,i,j,k} m_i^{n+1} + V_{b,i,j,k} m_i^{n+1} - V_{b,i,j,k} \sum_{j'=1}^J P_{i,j',i,j,k} \\
& -\frac{V_{b,i,j,k}}{\Delta t} [(\phi S_w \rho_w \frac{C_{io}}{f_{iow}})|_{i,j,k}^{n+1} - \phi S_w \rho_w \frac{C_{io}}{f_{iow}}|_{i,j,k}^n] + [(\phi(1 - S_w - S_g) \rho_o C_{io})|_{i,j,k}^{n+1} \\
& -[\phi(1 - S_w - S_g) \rho_o C_{io}]|_{i,j,k}^n] + (\phi S_g \rho_g \frac{C_{io}}{f_{iog}})|_{i,j,k}^{n+1} - \phi S_g \rho_g \frac{C_{io}}{f_{iog}}|_{i,j,k}^n] \quad (4.16)
\end{aligned}$$

where

$$T_z = T_{oz} + T_{wz} + T_{gz},$$

$$T_{ox} = \frac{A_x k_x k_{ro} \rho_o C_{io}}{\mu_o \Delta x} \Big|_{i \pm \frac{1}{2}, j, k},$$

$$T_{wx} = \frac{A_x k_x k_{rw} \rho_w C_{iw}}{\mu_w \Delta x} \Big|_{i \pm \frac{1}{2}, j, k},$$

$$T_{gx} = \frac{A_x k_x k_{rg} \rho_g C_{ig}}{\mu_g \Delta x} \Big|_{i \pm \frac{1}{2}, j, k},$$

and

$$T_{gsx} = T_{ox} \rho_o g + T_{wx} \rho_w g + T_{gx} \rho_g g,$$

where, for example,

$$T_{ox} \Big|_{i \pm \frac{1}{2}, j, k} = \frac{2A_{x, i+1, j, k} k_{x, i+1, j, k} A_{x, i, j, k} k_{x, i, j, k}}{A_{x, i+1, j, k} k_{x, i+1, j, k} \Delta x_{i, j, k} + A_{x, i, j, k} k_{x, i, j, k} \Delta x_{i+1, j, k}} \left(\frac{k_{ro} \rho_o C_{io}}{\mu_o} \right)_l^{(n+1)},$$

where

l is $i+1, j, k$: if $\Phi_{o, i+1, j, k}^{n+1} > \Phi_{o, i, j, k}^{n+1}$, or, l is i, j, k : if $\Phi_{o, i+1, j, k}^{n+1} \leq \Phi_{o, i, j, k}^{n+1}$.

Similar terms can be written for the y and z directions also. The above choice of l is based upon the well-known concept of upstream saturations.

Energy Balance

The energy balance equation (Eq.(4.12)) is discretized for a fully implicit formulation, as follows:

$$G_{i, j, k} = 0, \quad (4.17)$$

where G is given by

$$\begin{aligned} G_{i, j, k} = & \frac{A_x k_{hx}}{\Delta x} \Big|_{i \pm \frac{1}{2}, j, k}^{n+1} (T_{i+1, j, k}^{n+1} - T_{i, j, k}^{n+1}) - \frac{A_x k_{hx}}{\Delta x} \Big|_{i - \frac{1}{2}, j, k}^{n+1} (T_{i, j, k}^{n+1} - T_{i-1, j, k}^{n+1}) + \frac{A_y k_{hy}}{\Delta y} \Big|_{i, j \pm \frac{1}{2}, k}^{n+1} (T_{i, j+1, k}^{n+1} - T_{i, j, k}^{n+1}) \\ & - \frac{A_y k_{hy}}{\Delta y} \Big|_{i, j - \frac{1}{2}, k}^{n+1} (T_{i, j, k}^{n+1} - T_{i, j-1, k}^{n+1}) + \frac{A_z k_{hz}}{\Delta z} \Big|_{i, j, k \pm \frac{1}{2}}^{n+1} (T_{i, j, k+1}^{n+1} - T_{i, j, k}^{n+1}) - \frac{A_z k_{hz}}{\Delta z} \Big|_{i, j, k - \frac{1}{2}}^{n+1} (T_{i, j, k}^{n+1} - T_{i, j, k-1}^{n+1}) \\ & - V_{b, i, j, k} \Delta x \left(\rho_o v_{ox} T \sum_i (c_p, C_{io}) \right)_{i, j, k}^{n+1} - V_{b, i, j, k} \Delta y \left(\rho_o v_{oy} T \sum_i (c_p, C_{io}) \right)_{i, j, k}^{n+1} - V_{b, i, j, k} \Delta z \left(\rho_o v_{oz} T \sum_i (c_p, C_{io}) \right)_{i, j, k}^{n+1} \\ & - V_{b, i, j, k} \Delta x \left(\rho_w v_{wx} T \sum_i (c_p, \frac{C_{iw}}{f_{iow}}) \right)_{i, j, k}^{n+1} - V_{b, i, j, k} \Delta y \left(\rho_w v_{wy} T \sum_i (c_p, \frac{C_{iw}}{f_{iow}}) \right)_{i, j, k}^{n+1} \\ & - V_{b, i, j, k} \Delta z \left(\rho_g v_{gz} T \sum_i (c_p, \frac{C_{ig}}{f_{igw}}) \right)_{i, j, k}^{n+1} \end{aligned}$$

$$\begin{aligned}
& -V_{b,j,k} \Delta_x \left(\rho_w v_{wx} T \sum_i (c_p, \frac{C_{i_o}}{f_{i_o w}}) \right)_{i,j,k}^{n+1} - V_{b,j,k} \Delta_x \left(\rho_g v_{gx} T \sum_i (c_p, T + L_{v_i}) \frac{C_{i_o}}{f_{i_o g}} \right)_{i,j,k}^{n+1} \\
& - V_{b,j,k} \Delta_y \left(\rho_g v_{gy} T \sum_i (c_p, T + L_{v_i}) \frac{C_{i_o}}{f_{i_o g}} \right)_{i,j,k}^{n+1} - V_{b,j,k} \Delta_z \left(\rho_g v_{gz} T \sum_i (c_p, T + L_{v_i}) \frac{C_{i_o}}{f_{i_o g}} \right)_{i,j,k}^{n+1} \\
& + \sum_i \left[\frac{A_x D_{i_o} \rho_o c_p T}{\Delta x} \right]_{i+\frac{1}{2},j,k}^{n+1} (C_{i_o i+1,j,k}^{n+1} - C_{i_o i,j,k}^{n+1}) - \frac{A_x D_{i_o} \rho_o c_p T}{\Delta x} \left[\right]_{i-\frac{1}{2},j,k}^{n+1} (C_{i_o i,j,k}^{n+1} - C_{i_o i-1,j,k}^{n+1}) \\
& + \sum_i \left[\frac{A_y D_{i_o} \rho_o c_p T}{\Delta y} \right]_{i,j+\frac{1}{2},k}^{n+1} (C_{i_o i,j+1,k}^{n+1} - C_{i_o i,j,k}^{n+1}) - \frac{A_y D_{i_o} \rho_o c_p T}{\Delta y} \left[\right]_{i,j-\frac{1}{2},k}^{n+1} (C_{i_o i,j,k}^{n+1} - C_{i_o i,j-1,k}^{n+1}) \\
& + \sum_i \left[\frac{A_z D_{i_o} \rho_o c_p T}{\Delta z} \right]_{i,j,k+\frac{1}{2}}^{n+1} (C_{i_o i,j,k+1}^{n+1} - C_{i_o i,j,k}^{n+1}) - \frac{A_z D_{i_o} \rho_o c_p T}{\Delta z} \left[\right]_{i,j,k-\frac{1}{2}}^{n+1} (C_{i_o i,j,k}^{n+1} - C_{i_o i,j,k-1}^{n+1}) \\
& + \sum_i \left[\frac{A_x D_{i_w} \rho_w c_p T}{\Delta x} \right]_{i+\frac{1}{2},j,k}^{n+1} \left(\frac{C_{i_o}}{f_{i_o w i+1,j,k}} - \frac{C_{i_o}}{f_{i_o w i,j,k}} \right) - \frac{A_x D_{i_w} \rho_w c_p T}{\Delta x} \left[\right]_{i-\frac{1}{2},j,k}^{n+1} \left(\frac{C_{i_o}}{f_{i_o w i,j,k}} - \frac{C_{i_o}}{f_{i_o w i-1,j,k}} \right) \\
& + \sum_i \left[\frac{A_y D_{i_w} \rho_w c_p T}{\Delta y} \right]_{i,j+\frac{1}{2},k}^{n+1} \left(\frac{C_{i_o}}{f_{i_o w i,j+1,k}} - \frac{C_{i_o}}{f_{i_o w i,j,k}} \right) - \frac{A_y D_{i_w} \rho_w c_p T}{\Delta y} \left[\right]_{i,j-\frac{1}{2},k}^{n+1} \left(\frac{C_{i_o}}{f_{i_o w i,j,k}} - \frac{C_{i_o}}{f_{i_o w i,j-1,k}} \right) \\
& + \sum_i \left[\frac{A_z D_{i_w} \rho_w c_p T}{\Delta z} \right]_{i,j,k+\frac{1}{2}}^{n+1} \left(\frac{C_{i_o}}{f_{i_o w i,j,k+1}} - \frac{C_{i_o}}{f_{i_o w i,j,k}} \right) - \frac{A_z D_{i_w} \rho_w c_p T}{\Delta z} \left[\right]_{i,j,k-\frac{1}{2}}^{n+1} \left(\frac{C_{i_o}}{f_{i_o w i,j,k}} - \frac{C_{i_o}}{f_{i_o w i,j,k-1}} \right) \\
& + \sum_i \left[\frac{A_x D_{i_g} \rho_g (c_p, T + L_{v_i})}{\Delta x} \right]_{i+\frac{1}{2},j,k}^{n+1} \left(\frac{C_{i_o}}{f_{i_o g i+1,j,k}} - \frac{C_{i_o}}{f_{i_o g i,j,k}} \right) - \frac{A_x D_{i_g} \rho_g (c_p, T + L_{v_i})}{\Delta x} \left[\right]_{i-\frac{1}{2},j,k}^{n+1} \left(\frac{C_{i_o}}{f_{i_o g i,j,k}} - \frac{C_{i_o}}{f_{i_o g i-1,j,k}} \right) \\
& + \sum_i \left[\frac{A_y D_{i_g} \rho_g (c_p, T + L_{v_i})}{\Delta y} \right]_{i,j+\frac{1}{2},k}^{n+1} \left(\frac{C_{i_o}}{f_{i_o g i,j+1,k}} - \frac{C_{i_o}}{f_{i_o g i,j,k}} \right) - \frac{A_y D_{i_g} \rho_g (c_p, T + L_{v_i})}{\Delta y} \left[\right]_{i,j-\frac{1}{2},k}^{n+1} \left(\frac{C_{i_o}}{f_{i_o g i,j,k}} - \frac{C_{i_o}}{f_{i_o g i,j-1,k}} \right) \\
& + \sum_i \left[\frac{A_z D_{i_g} \rho_g (c_p, T + L_{v_i})}{\Delta z} \right]_{i,j,k+\frac{1}{2}}^{n+1} \left(\frac{C_{i_o}}{f_{i_o g i,j,k+1}} - \frac{C_{i_o}}{f_{i_o g i,j,k}} \right) - \frac{A_z D_{i_g} \rho_g (c_p, T + L_{v_i})}{\Delta z} \left[\right]_{i,j,k-\frac{1}{2}}^{n+1} \left(\frac{C_{i_o}}{f_{i_o g i,j,k}} - \frac{C_{i_o}}{f_{i_o g i,j,k-1}} \right) \\
& + V_{b,j,k} [-q_L^* + r_H^* + \frac{q_o^* \rho_o}{M_o} \sum_i x_{i_o} h_{i_o i,j,k}^{n+1} + \frac{q_w^* \rho_w}{M_w} \sum_i x_{i_w} h_{i_w i,j,k}^{n+1} + \frac{q_g^* \rho_g}{M_g} \sum_i x_{i_g} h_{i_g i,j,k}^{n+1}]_{i,j,k}^{n+1} \\
& - \frac{V_{b,j,k}}{\Delta t} [((1-\phi) \frac{\rho_s}{M_s} h_s)_{i,j,k}^{n+1} - (1-\phi) \frac{\rho_s}{M_s} h_s)_{i,j,k}^n] + (\phi \rho_o (1 - S_w - S_g) \sum_i c_p, C_{i_o} T)_{i,j,k}^{n+1} - \\
& \phi \rho_o (1 - S_w - S_g) \sum_i c_p, C_{i_o} T)_{i,j,k}^n + (\phi \rho_w S_w \sum_i c_p, \frac{C_{i_o}}{f_{i_o w}} T)_{i,j,k}^{n+1} - \phi \rho_w S_w \sum_i c_p, \frac{C_{i_o}}{f_{i_o w}} T)_{i,j,k}^n \\
& + (\phi \rho_g S_g \sum_i (c_p, T + L_{v_i}) \frac{C_{i_o}}{f_{i_o g}})_{i,j,k}^{n+1} - \phi \rho_g S_g \sum_i (c_p, T + L_{v_i}) \frac{C_{i_o}}{f_{i_o g}})_{i,j,k}^n \quad (4.18)
\end{aligned}$$

The convection terms in the above equation are given by the following expressions:

$$\begin{aligned}
V_{b,j,k} \Delta_x \left(\rho_o v_{ox} T \sum_i (c_p, C_{i_o}) \right)_{i,j,k}^{n+1} &= - \frac{A_x k_x k_{ro} \rho_o}{\mu_o \Delta x} \left[\right]_{i,j,k}^{n+1} (s_{i+1} p_{o i+1,j,k}^{n+1} + s_i p_{o i,j,k}^{n+1} + s_{i-1} p_{o i-1,j,k}^{n+1} \\
&\quad - s_{i+1} g D_{i+1,j,k} \rho_{o i+1,j,k}^{n+1} - s_i g D_{i,j,k} \rho_{o i,j,k}^{n+1} - s_{i-1} g D_{i-1,j,k} \rho_{o i-1,j,k}^{n+1}) \\
&\quad \cdot (s_{i+1} T_{i+1,j,k}^{n+1} \sum_i (c_p, C_{i_o})_{i+1,j,k}^{n+1} + s_i T_{i,j,k}^{n+1} \sum_i (c_p, C_{i_o})_{i,j,k}^{n+1} + s_{i-1} T_{i-1,j,k}^{n+1} \sum_i (c_p, C_{i_o})_{i-1,j,k}^{n+1}) \\
&\quad - T_{i,j,k}^{n+1} \sum_i (c_p, C_{i_o})_{i,j,k}^{n+1} \left[(w_{o_s} \frac{A_x k_x k_{ro} \rho_o}{\mu_o \Delta x} \left[\right]_{i,j,k}^{n+1} + (1 - w_{o_s}) \frac{A_x k_x k_{ro} \rho_o}{\mu_o \Delta x} \left[\right]_{i+1,j,k}^{n+1}) (p_{o i+1,j,k}^{n+1} - p_{o i,j,k}^{n+1}) \right]
\end{aligned}$$

$$\begin{aligned}
& -\{w^*_{o_x} \frac{A_x k_x k_{ro} \rho_o}{\mu_o \Delta x} |_{i,j,k}^{n+1} + (1 - w^*_{o_x}) \frac{A_x k_x k_{ro} \rho_o}{\mu_o \Delta x} |_{i-1,j,k}^{n+1}\} (p_{o,i,j,k}^{n+1} - p_{o,i-1,j,k}^{n+1}) \\
& -\{w_{o_x} \frac{A_x k_x k_{ro} \rho_o}{\mu_o \Delta x} |_{i,j,k}^{n+1} + (1 - w_{o_x}) \frac{A_x k_x k_{ro} \rho_o}{\mu_o \Delta x} |_{i+1,j,k}^{n+1}\} g(\rho_{o,i+1,j,k}^{n+1} D_{i+1,j,k} - \rho_{o,i,j,k}^{n+1} D_{i,j,k}) \\
& +\{w^*_{o_x} \frac{A_x k_x k_{ro} \rho_o}{\mu_o \Delta x} |_{i,j,k}^{n+1} + (1 - w^*_{o_x}) \frac{A_x k_x k_{ro} \rho_o}{\mu_o \Delta x} |_{i-1,j,k}^{n+1}\} g(\rho_{o,i-1,j,k}^{n+1} D_{i-1,j,k} - \rho_{o,i,j,k}^{n+1} D_{i,j,k}) \Big]
\end{aligned} \tag{4.19}$$

$$\begin{aligned}
V_{\delta,i,j,k} \Delta_y \left(\rho_o v_{oy} T \sum_i (c_p, C_{i_o}) \right)_{i,j,k}^{n+1} &= -\frac{A_y k_y k_{ro} \rho_o}{\mu_o \Delta y} |_{i,j,k}^{n+1} (s_{j+1} p_{o,i,j+1,k}^{n+1} + s_j p_{o,i,j,k}^{n+1} + s_{j-1} p_{o,i,j-1,k}^{n+1} \\
&\quad - s_{j+1} g D_{i,j+1,k} \rho_{o,i,j+1,k}^{n+1} - s_j g D_{i,j,k} \rho_{o,i,j,k}^{n+1} - s_{j-1} g D_{i,j-1,k} \rho_{o,i,j-1,k}^{n+1}) \\
&\quad \cdot (s_{j+1} T_{i,j+1,k}^{n+1} \sum_i (c_p, C_{i_o}) |_{i,j+1,k}^{n+1} + s_j T_{i,j,k}^{n+1} \sum_i (c_p, C_{i_o}) |_{i,j,k}^{n+1} + s_{j-1} T_{i,j-1,k}^{n+1} \sum_i (c_p, C_{i_o}) |_{i,j-1,k}^{n+1}) \\
&\quad - T_{i,j,k}^{n+1} \sum_i (c_p, C_{i_o}) |_{i,j,k}^{n+1} \Big[\{w_{o_y} \frac{A_y k_y k_{ro} \rho_o}{\mu_o \Delta y} |_{i,j,k}^{n+1} + (1 - w_{o_y}) \frac{A_y k_y k_{ro} \rho_o}{\mu_o \Delta y} |_{i,j+1,k}^{n+1}\} (p_{o,i,j+1,k}^{n+1} - p_{o,i,j,k}^{n+1}) \\
&\quad - \{w^*_{o_y} \frac{A_y k_y k_{ro} \rho_o}{\mu_o \Delta y} |_{i,j,k}^{n+1} + (1 - w^*_{o_y}) \frac{A_y k_y k_{ro} \rho_o}{\mu_o \Delta y} |_{i,j-1,k}^{n+1}\} (p_{o,i,j,k}^{n+1} - p_{o,i,j-1,k}^{n+1}) \\
&\quad - \{w_{o_y} \frac{A_y k_y k_{ro} \rho_o}{\mu_o \Delta y} |_{i,j,k}^{n+1} + (1 - w_{o_y}) \frac{A_y k_y k_{ro} \rho_o}{\mu_o \Delta y} |_{i,j+1,k}^{n+1}\} g(\rho_{o,i,j+1,k}^{n+1} D_{i,j+1,k} - \rho_{o,i,j,k}^{n+1} D_{i,j,k}) \\
&\quad + \{w^*_{o_y} \frac{A_y k_y k_{ro} \rho_o}{\mu_o \Delta y} |_{i,j,k}^{n+1} + (1 - w^*_{o_y}) \frac{A_y k_y k_{ro} \rho_o}{\mu_o \Delta y} |_{i,j-1,k}^{n+1}\} g(\rho_{o,i,j-1,k}^{n+1} D_{i,j-1,k} - \rho_{o,i,j,k}^{n+1} D_{i,j,k}) \Big]
\end{aligned} \tag{4.20}$$

$$\begin{aligned}
V_{\delta,i,j,k} \Delta_z \left(\rho_o v_{oz} T \sum_i (c_p, C_{i_o}) \right)_{i,j,k}^{n+1} &= -\frac{A_z k_z k_{ro} \rho_o}{\mu_o \Delta z} |_{i,j,k}^{n+1} (s_{k+1} p_{o,i,j,k+1}^{n+1} + s_k p_{o,i,j,k}^{n+1} + s_{k-1} p_{o,i,j,k-1}^{n+1} \\
&\quad - s_{k+1} g D_{i,j,k+1} \rho_{o,i,j,k+1}^{n+1} - s_k g D_{i,j,k} \rho_{o,i,j,k}^{n+1} - s_{k-1} g D_{i,j,k-1} \rho_{o,i,j,k-1}^{n+1}) \\
&\quad \cdot (s_{k+1} T_{i,j,k+1}^{n+1} \sum_i (c_p, C_{i_o}) |_{i,j,k+1}^{n+1} + s_k T_{i,j,k}^{n+1} \sum_i (c_p, C_{i_o}) |_{i,j,k}^{n+1} + s_{k-1} T_{i,j,k-1}^{n+1} \sum_i (c_p, C_{i_o}) |_{i,j,k-1}^{n+1}) \\
&\quad - T_{i,j,k}^{n+1} \sum_i (c_p, C_{i_o}) |_{i,j,k}^{n+1} \Big[\{w_{o_z} \frac{A_z k_z k_{ro} \rho_o}{\mu_o \Delta z} |_{i,j,k}^{n+1} + (1 - w_{o_z}) \frac{A_z k_z k_{ro} \rho_o}{\mu_o \Delta z} |_{i,j,k+1}^{n+1}\} (p_{o,i,j,k+1}^{n+1} - p_{o,i,j,k}^{n+1}) \\
&\quad - \{w^*_{o_z} \frac{A_z k_z k_{ro} \rho_o}{\mu_o \Delta z} |_{i,j,k}^{n+1} + (1 - w^*_{o_z}) \frac{A_z k_z k_{ro} \rho_o}{\mu_o \Delta z} |_{i,j,k-1}^{n+1}\} (p_{o,i,j,k}^{n+1} - p_{o,i,j,k-1}^{n+1}) \\
&\quad - \{w_{o_z} \frac{A_z k_z k_{ro} \rho_o}{\mu_o \Delta z} |_{i,j,k}^{n+1} + (1 - w_{o_z}) \frac{A_z k_z k_{ro} \rho_o}{\mu_o \Delta z} |_{i,j,k+1}^{n+1}\} g(\rho_{o,i,j,k+1}^{n+1} D_{i,j,k+1} - \rho_{o,i,j,k}^{n+1} D_{i,j,k}) \\
&\quad + \{w^*_{o_z} \frac{A_z k_z k_{ro} \rho_o}{\mu_o \Delta z} |_{i,j,k}^{n+1} + (1 - w^*_{o_z}) \frac{A_z k_z k_{ro} \rho_o}{\mu_o \Delta z} |_{i,j,k-1}^{n+1}\} g(\rho_{o,i,j,k-1}^{n+1} D_{i,j,k-1} - \rho_{o,i,j,k}^{n+1} D_{i,j,k}) \Big]
\end{aligned}$$

(4.21)

$$\begin{aligned}
V_{b,i,j,k} \Delta_x \left(\rho_w v_{wx} T \sum_i \left(c_p, \frac{C_{i_o}}{f_{i_o w}} \right) \right)_{i,j,k}^{n+1} &= - \frac{A_x k_x k_{rw} \rho_w}{\mu_w \Delta x} \Big|_{i,j,k}^{n+1} (s_{i+1} p_{o,i+1,j,k}^{n+1} + s_i p_{o,i,j,k}^{n+1} + s_{i-1} p_{o,i-1,j,k}^{n+1} \\
&\quad - s_{i+1} P_{cow,i+1,j,k}^{n+1} - s_i P_{cow,i,j,k}^{n+1} + s_{i-1} P_{cow,i-1,j,k}^{n+1} \\
&\quad - s_{i+1} g D_{i+1,j,k} \rho_{w,i+1,j,k}^{n+1} - s_i g D_{i,j,k} \rho_{w,i,j,k}^{n+1} - s_{i-1} g D_{i-1,j,k} \rho_{w,i-1,j,k}^{n+1}) \\
&\quad \cdot (s_{i+1} T_{i+1,j,k}^{n+1} \sum_i \left(c_p, \frac{C_{i_o}}{f_{i_o w}} \right)_{i+1,j,k}^{n+1} + s_i T_{i,j,k}^{n+1} \sum_i \left(c_p, \frac{C_{i_o}}{f_{i_o w}} \right)_{i,j,k}^{n+1} + s_{i-1} T_{i-1,j,k}^{n+1} \sum_i \left(c_p, \frac{C_{i_o}}{f_{i_o w}} \right)_{i-1,j,k}^{n+1}) \\
&\quad - T_{i,j,k}^{n+1} \sum_i \left(c_p, \frac{C_{i_o}}{f_{i_o w}} \right)_{i,j,k}^{n+1} \left[\{ w_{w_s} \frac{A_x k_x k_{rw} \rho_w}{\mu_w \Delta x} \Big|_{i,j,k}^{n+1} + (1 - w_{w_s}) \frac{A_x k_x k_{rw} \rho_w}{\mu_w \Delta x} \Big|_{i+1,j,k}^{n+1} \} (p_{o,i+1,j,k}^{n+1} - p_{o,i,j,k}^{n+1}) \right. \\
&\quad - \{ w_{w_s} \frac{A_x k_x k_{rw} \rho_w}{\mu_w \Delta x} \Big|_{i,j,k}^{n+1} + (1 - w_{w_s}) \frac{A_x k_x k_{rw} \rho_w}{\mu_w \Delta x} \Big|_{i+1,j,k}^{n+1} \} (P_{cow,i+1,j,k}^{n+1} - P_{cow,i,j,k}^{n+1}) \\
&\quad - \{ w^*_{w_s} \frac{A_x k_x k_{rw} \rho_w}{\mu_w \Delta x} \Big|_{i,j,k}^{n+1} + (1 - w^*_{w_s}) \frac{A_x k_x k_{rw} \rho_w}{\mu_w \Delta x} \Big|_{i-1,j,k}^{n+1} \} (p_{o,i,j,k}^{n+1} - p_{o,i-1,j,k}^{n+1}) \\
&\quad + \{ w^*_{w_s} \frac{A_x k_x k_{rw} \rho_w}{\mu_w \Delta x} \Big|_{i,j,k}^{n+1} + (1 - w^*_{w_s}) \frac{A_x k_x k_{rw} \rho_w}{\mu_w \Delta x} \Big|_{i-1,j,k}^{n+1} \} (P_{cow,i,j,k}^{n+1} - P_{cow,i-1,j,k}^{n+1}) \\
&\quad - \{ w_{w_s} \frac{A_x k_x k_{rw} \rho_w}{\mu_w \Delta x} \Big|_{i,j,k}^{n+1} + (1 - w_{w_s}) \frac{A_x k_x k_{rw} \rho_w}{\mu_w \Delta x} \Big|_{i+1,j,k}^{n+1} \} g (\rho_{w,i+1,j,k}^{n+1} D_{i+1,j,k} - \rho_{w,i,j,k}^{n+1} D_{i,j,k}) \\
&\quad \left. + \{ w^*_{w_s} \frac{A_x k_x k_{rw} \rho_w}{\mu_w \Delta x} \Big|_{i,j,k}^{n+1} + (1 - w^*_{w_s}) \frac{A_x k_x k_{rw} \rho_w}{\mu_w \Delta x} \Big|_{i-1,j,k}^{n+1} \} g (\rho_{w,i-1,j,k}^{n+1} D_{i-1,j,k} - \rho_{w,i,j,k}^{n+1} D_{i,j,k}) \right]
\end{aligned}
\tag{4.22}$$

$$\begin{aligned}
V_{b,i,j,k} \Delta_y \left(\rho_w v_{wy} T \sum_i \left(c_p, \frac{C_{i_o}}{f_{i_o w}} \right) \right)_{i,j,k}^{n+1} &= - \frac{A_y k_y k_{rw} \rho_w}{\mu_w \Delta y} \Big|_{i,j,k}^{n+1} (s_{j+1} p_{o,i,j+1,k}^{n+1} + s_j p_{o,i,j,k}^{n+1} + s_{j-1} p_{o,i,j-1,k}^{n+1} \\
&\quad - s_{j+1} P_{cow,i,j+1,k}^{n+1} - s_j P_{cow,i,j,k}^{n+1} + s_{j-1} P_{cow,i,j-1,k}^{n+1} \\
&\quad - s_{j+1} g D_{i,j+1,k} \rho_{w,i,j+1,k}^{n+1} - s_j g D_{i,j,k} \rho_{w,i,j,k}^{n+1} - s_{j-1} g D_{i,j-1,k} \rho_{w,i,j-1,k}^{n+1}) \\
&\quad \cdot (s_{j+1} T_{i,j+1,k}^{n+1} \sum_i \left(c_p, \frac{C_{i_o}}{f_{i_o w}} \right)_{i,j+1,k}^{n+1} + s_j T_{i,j,k}^{n+1} \sum_i \left(c_p, \frac{C_{i_o}}{f_{i_o w}} \right)_{i,j,k}^{n+1} + s_{j-1} T_{i,j-1,k}^{n+1} \sum_i \left(c_p, \frac{C_{i_o}}{f_{i_o w}} \right)_{i,j-1,k}^{n+1}) \\
&\quad - T_{i,j,k}^{n+1} \sum_i \left(c_p, \frac{C_{i_o}}{f_{i_o w}} \right)_{i,j,k}^{n+1} \left[\{ w_{w_y} \frac{A_y k_y k_{rw} \rho_w}{\mu_w \Delta y} \Big|_{i,j,k}^{n+1} + (1 - w_{w_y}) \frac{A_y k_y k_{rw} \rho_w}{\mu_w \Delta y} \Big|_{i,j+1,k}^{n+1} \} (p_{o,i,j+1,k}^{n+1} - p_{o,i,j,k}^{n+1}) \right. \\
&\quad - \{ w_{w_y} \frac{A_y k_y k_{rw} \rho_w}{\mu_w \Delta y} \Big|_{i,j,k}^{n+1} + (1 - w_{w_y}) \frac{A_y k_y k_{rw} \rho_w}{\mu_w \Delta y} \Big|_{i,j+1,k}^{n+1} \} (P_{cow,i,j+1,k}^{n+1} - P_{cow,i,j,k}^{n+1}) \\
&\quad - \{ w^*_{w_y} \frac{A_y k_y k_{rw} \rho_w}{\mu_w \Delta y} \Big|_{i,j,k}^{n+1} + (1 - w^*_{w_y}) \frac{A_y k_y k_{rw} \rho_w}{\mu_w \Delta y} \Big|_{i,j-1,k}^{n+1} \} (p_{o,i,j,k}^{n+1} - p_{o,i,j-1,k}^{n+1}) \\
&\quad \left. + \{ w^*_{w_y} \frac{A_y k_y k_{rw} \rho_w}{\mu_w \Delta y} \Big|_{i,j,k}^{n+1} + (1 - w^*_{w_y}) \frac{A_y k_y k_{rw} \rho_w}{\mu_w \Delta y} \Big|_{i,j-1,k}^{n+1} \} (P_{cow,i,j,k}^{n+1} - P_{cow,i,j-1,k}^{n+1}) \right]
\end{aligned}$$

$$\begin{aligned}
& -\left\{w_w \frac{A_y k_y k_{rw} \rho_w}{\mu_w \Delta y} \Big|_{i,j,k}^{n+1} + (1-w_w) \frac{A_y k_y k_{rw} \rho_w}{\mu_w \Delta y} \Big|_{i,j+1,k}^{n+1}\right\} g(\rho_{w,i,j+1,k}^{n+1} D_{i,j+1,k} - \rho_{w,i,j,k}^{n+1} D_{i,j,k}) \\
& + \left\{w^* w_w \frac{A_y k_y k_{rw} \rho_w}{\mu_w \Delta y} \Big|_{i,j,k}^{n+1} + (1-w^* w_w) \frac{A_y k_y k_{rw} \rho_w}{\mu_w \Delta y} \Big|_{i,j-1,k}^{n+1}\right\} g(\rho_{w,i,j-1,k}^{n+1} D_{i,j-1,k} - \rho_{w,i,j,k}^{n+1} D_{i,j,k}) \Big] \\
\end{aligned} \tag{4.23}$$

$$\begin{aligned}
V_{b,i,j,k} \Delta z \left(\rho_w v_{ws} T \sum_i \left(c_p, \frac{C_{i_o}}{f_{iow}} \right) \Big|_{i,j,k}^{n+1} \right) &= - \frac{A_z k_z k_{rw} \rho_w}{\mu_w \Delta z} \Big|_{i,j,k}^{n+1} (s_{k+1} p_{o,i,j,k+1}^{n+1} + s_k p_{o,i,j,k}^{n+1} + s_{k-1} p_{o,i,j,k-1}^{n+1} \\
&\quad - s_{k+1} P_{cow,i,j,k+1}^{n+1} - s_k P_{cow,i,j,k}^{n+1} + s_{k-1} P_{cow,i,j,k-1}^{n+1}) \\
&\quad - s_{k+1} g D_{i,j,k+1} \rho_{w,i,j,k+1}^{n+1} - s_k g D_{i,j,k} \rho_{w,i,j,k}^{n+1} - s_{k-1} g D_{i,j,k-1} \rho_{w,i,j,k-1}^{n+1}) \\
&\cdot (s_{k+1} T_{i,j,k+1}^{n+1} \sum_i \left(c_p, \frac{C_{i_o}}{f_{iow}} \right) \Big|_{i,j,k+1}^{n+1} + s_k T_{i,j,k}^{n+1} \sum_i \left(c_p, \frac{C_{i_o}}{f_{iow}} \right) \Big|_{i,j,k}^{n+1} + s_{k-1} T_{i,j,k-1}^{n+1} \sum_i \left(c_p, \frac{C_{i_o}}{f_{iow}} \right) \Big|_{i,j,k-1}^{n+1}) \\
&- T_{i,j,k}^{n+1} \sum_i \left(c_p, \frac{C_{i_o}}{f_{iow}} \right) \Big|_{i,j,k}^{n+1} \left[\left\{ w_w \frac{A_z k_z k_{rw} \rho_w}{\mu_w \Delta z} \Big|_{i,j,k}^{n+1} + (1-w_w) \frac{A_z k_z k_{rw} \rho_w}{\mu_w \Delta z} \Big|_{i,j,k+1}^{n+1} \right\} (p_{o,i,j,k+1}^{n+1} - p_{o,i,j,k}^{n+1}) \right. \\
&\quad - \left\{ w_w \frac{A_z k_z k_{rw} \rho_w}{\mu_w \Delta z} \Big|_{i,j,k}^{n+1} + (1-w_w) \frac{A_z k_z k_{rw} \rho_w}{\mu_w \Delta z} \Big|_{i,j,k+1}^{n+1} \right\} (P_{cow,i,j,k+1}^{n+1} - P_{cow,i,j,k}^{n+1}) \\
&\quad - \left\{ w^* w_w \frac{A_z k_z k_{rw} \rho_w}{\mu_w \Delta z} \Big|_{i,j,k}^{n+1} + (1-w^* w_w) \frac{A_z k_z k_{rw} \rho_w}{\mu_w \Delta z} \Big|_{i,j,k-1}^{n+1} \right\} (p_{o,i,j,k}^{n+1} - p_{o,i,j,k-1}^{n+1}) \\
&\quad + \left\{ w^* w_w \frac{A_z k_z k_{rw} \rho_w}{\mu_w \Delta z} \Big|_{i,j,k}^{n+1} + (1-w^* w_w) \frac{A_z k_z k_{rw} \rho_w}{\mu_w \Delta z} \Big|_{i,j,k-1}^{n+1} \right\} (P_{cow,i,j,k}^{n+1} - P_{cow,i,j,k-1}^{n+1}) \\
&\quad - \left\{ w_w \frac{A_z k_z k_{rw} \rho_w}{\mu_w \Delta z} \Big|_{i,j,k}^{n+1} + (1-w_w) \frac{A_z k_z k_{rw} \rho_w}{\mu_w \Delta z} \Big|_{i,j,k+1}^{n+1} \right\} g(\rho_{w,i,j,k+1}^{n+1} D_{i,j,k+1} - \rho_{w,i,j,k}^{n+1} D_{i,j,k}) \\
&\quad \left. + \left\{ w^* w_w \frac{A_z k_z k_{rw} \rho_w}{\mu_w \Delta z} \Big|_{i,j,k}^{n+1} + (1-w^* w_w) \frac{A_z k_z k_{rw} \rho_w}{\mu_w \Delta z} \Big|_{i,j,k-1}^{n+1} \right\} g(\rho_{w,i,j,k-1}^{n+1} D_{i,j,k-1} - \rho_{w,i,j,k}^{n+1} D_{i,j,k}) \right] \\
\end{aligned} \tag{4.24}$$

$$\begin{aligned}
V_{b,i,j,k} \Delta x \left(\rho_g v_{gx} T \sum_i \left(c_p, T + L_{vi} \right) \frac{C_{i_o}}{f_{iog}} \Big|_{i,j,k}^{n+1} \right) &= - \frac{A_x k_x k_{rg} \rho_g}{\mu_g \Delta x} \Big|_{i,j,k}^{n+1} (s_{i+1} p_{o,i+1,j,k}^{n+1} + s_i p_{o,i,j,k}^{n+1} + s_{i-1} p_{o,i-1,j,k}^{n+1} \\
&\quad + s_{i+1} P_{ego,i+1,j,k}^{n+1} + s_i P_{ego,i,j,k}^{n+1} + s_{i-1} P_{ego,i-1,j,k}^{n+1}) \\
&\quad - s_{i+1} g D_{i+1,j,k} \rho_{g,i+1,j,k}^{n+1} - s_i g D_{i,j,k} \rho_{g,i,j,k}^{n+1} - s_{i-1} g D_{i-1,j,k} \rho_{g,i-1,j,k}^{n+1}) \\
&\cdot (s_{i+1} \sum_i \left(c_p, T + L_{vi} \right) \frac{C_{i_o}}{f_{iog}} \Big|_{i+1,j,k}^{n+1} + s_i \sum_i \left(c_p, T + L_{vi} \right) \frac{C_{i_o}}{f_{iog}} \Big|_{i,j,k}^{n+1} + s_{i-1} \sum_i \left(c_p, T + L_{vi} \right) \frac{C_{i_o}}{f_{iog}} \Big|_{i-1,j,k}^{n+1}) \\
&- \sum_i \left(c_p, T + L_{vi} \right) \frac{C_{i_o}}{f_{iog}} \Big|_{i,j,k}^{n+1} \left[\left\{ w_g \frac{A_x k_x k_{rg} \rho_g}{\mu_g \Delta x} \Big|_{i,j,k}^{n+1} + (1-w_g) \frac{A_x k_x k_{rg} \rho_g}{\mu_g \Delta x} \Big|_{i+1,j,k}^{n+1} \right\} (p_{o,i+1,j,k}^{n+1} - p_{o,i,j,k}^{n+1}) \right. \\
&\quad \left. + \left\{ w^* w_g \frac{A_x k_x k_{rg} \rho_g}{\mu_g \Delta x} \Big|_{i,j,k}^{n+1} + (1-w^* w_g) \frac{A_x k_x k_{rg} \rho_g}{\mu_g \Delta x} \Big|_{i-1,j,k}^{n+1} \right\} (p_{o,i,j,k}^{n+1} - p_{o,i-1,j,k}^{n+1}) \right] \\
\end{aligned}$$

$$\begin{aligned}
& + \{w_{g_s} \frac{A_x k_x k_{rg} \rho_g}{\mu_g \Delta x} |_{i,j,k}^{n+1} + (1 - w_{g_s}) \frac{A_x k_x k_{rg} \rho_g}{\mu_g \Delta x} |_{i+1,j,k}^{n+1}\} (P_{cgo_{i+1,j,k}}^{n+1} - P_{cgo_{i,j,k}}^{n+1}) \\
& - \{w_{g_s}^* \frac{A_x k_x k_{rg} \rho_g}{\mu_g \Delta x} |_{i,j,k}^{n+1} + (1 - w_{g_s}^*) \frac{A_x k_x k_{rg} \rho_g}{\mu_g \Delta x} |_{i-1,j,k}^{n+1}\} (p_{oi,j,k}^{n+1} - p_{oi-1,j,k}^{n+1}) \\
& - \{w_{g_s}^* \frac{A_x k_x k_{rg} \rho_g}{\mu_g \Delta x} |_{i,j,k}^{n+1} + (1 - w_{g_s}^*) \frac{A_x k_x k_{rg} \rho_g}{\mu_g \Delta x} |_{i-1,j,k}^{n+1}\} (P_{cgo_{i,j,k}}^{n+1} - P_{cgo_{i-1,j,k}}^{n+1}) \\
& - \{w_{g_s} \frac{A_x k_x k_{rg} \rho_g}{\mu_g \Delta x} |_{i,j,k}^{n+1} + (1 - w_{g_s}) \frac{A_x k_x k_{rg} \rho_g}{\mu_g \Delta x} |_{i+1,j,k}^{n+1}\} g(\rho_{gi+1,j,k}^{n+1} D_{i+1,j,k} - \rho_{gi,j,k}^{n+1} D_{i,j,k}) \\
& + \{w_{g_s}^* \frac{A_x k_x k_{rg} \rho_g}{\mu_g \Delta x} |_{i,j,k}^{n+1} + (1 - w_{g_s}^*) \frac{A_x k_x k_{rg} \rho_g}{\mu_g \Delta x} |_{i-1,j,k}^{n+1}\} g(\rho_{gi-1,j,k}^{n+1} D_{i-1,j,k} - \rho_{gi,j,k}^{n+1} D_{i,j,k}) \Big]
\end{aligned} \tag{4.25}$$

$$\begin{aligned}
V_{k,j,k} \Delta_y (\rho_g v_{gy} T \sum_i (c_{p,i} T + L_{vi}) \frac{C_{i\alpha}}{f_{i\alpha g}})^{n+1} &= - \frac{A_y k_y k_{rg} \rho_g}{\mu_g \Delta y} |_{i,j,k}^{n+1} (s_{j+1} p_{oi,j+1,k}^{n+1} + s_j p_{oi,j,k}^{n+1} + s_{j-1} p_{oi,j-1,k}^{n+1} \\
& + s_{j+1} P_{cgo_{i,j+1,k}}^{n+1} + s_j P_{cgo_{i,j,k}}^{n+1} + s_{j-1} P_{cgo_{i,j-1,k}}^{n+1} \\
& - s_{j+1} g D_{i,j+1,k} \rho_{gi,j+1,k}^{n+1} - s_j g D_{i,j,k} \rho_{gi,j,k}^{n+1} - s_{j-1} g D_{i,j-1,k} \rho_{gi,j-1,k}^{n+1}) \\
& \cdot (s_{j+1} \sum_i (c_{p,i} T + L_{vi}) \frac{C_{i\alpha}}{f_{i\alpha g}} |_{i,j+1,k}^{n+1} + s_j \sum_i (c_{p,i} T + L_{vi}) \frac{C_{i\alpha}}{f_{i\alpha g}} |_{i,j,k}^{n+1} + s_{j-1} \sum_i (c_{p,i} T + L_{vi}) \frac{C_{i\alpha}}{f_{i\alpha g}} |_{i,j-1,k}^{n+1}) \\
& - \sum_i (c_{p,i} T + L_{vi}) \frac{C_{i\alpha}}{f_{i\alpha g}} |_{i,j,k}^{n+1} \Big[\{w_{g_v} \frac{A_y k_y k_{rg} \rho_g}{\mu_g \Delta y} |_{i,j,k}^{n+1} + (1 - w_{g_v}) \frac{A_y k_y k_{rg} \rho_g}{\mu_g \Delta y} |_{i,j+1,k}^{n+1}\} (p_{oi,j+1,k}^{n+1} - p_{oi,j,k}^{n+1}) \\
& + \{w_{g_v} \frac{A_y k_y k_{rg} \rho_g}{\mu_g \Delta y} |_{i,j,k}^{n+1} + (1 - w_{g_v}) \frac{A_y k_y k_{rg} \rho_g}{\mu_g \Delta y} |_{i,j+1,k}^{n+1}\} (P_{cgo_{i,j+1,k}}^{n+1} - P_{cgo_{i,j,k}}^{n+1}) \\
& - \{w_{g_v}^* \frac{A_y k_y k_{rg} \rho_g}{\mu_g \Delta y} |_{i,j,k}^{n+1} + (1 - w_{g_v}^*) \frac{A_y k_y k_{rg} \rho_g}{\mu_g \Delta y} |_{i,j-1,k}^{n+1}\} (p_{oi,j,k}^{n+1} - p_{oi,j-1,k}^{n+1}) \\
& - \{w_{g_v}^* \frac{A_y k_y k_{rg} \rho_g}{\mu_g \Delta y} |_{i,j,k}^{n+1} + (1 - w_{g_v}^*) \frac{A_y k_y k_{rg} \rho_g}{\mu_g \Delta y} |_{i,j-1,k}^{n+1}\} (P_{cgo_{i,j,k}}^{n+1} - P_{cgo_{i,j-1,k}}^{n+1}) \\
& - \{w_{g_v} \frac{A_y k_y k_{rg} \rho_g}{\mu_g \Delta y} |_{i,j,k}^{n+1} + (1 - w_{g_v}) \frac{A_y k_y k_{rg} \rho_g}{\mu_g \Delta y} |_{i,j+1,k}^{n+1}\} g(\rho_{gi,j+1,k}^{n+1} D_{i,j+1,k} - \rho_{gi,j,k}^{n+1} D_{i,j,k}) \\
& + \{w_{g_v}^* \frac{A_y k_y k_{rg} \rho_g}{\mu_g \Delta y} |_{i,j,k}^{n+1} + (1 - w_{g_v}^*) \frac{A_y k_y k_{rg} \rho_g}{\mu_g \Delta y} |_{i,j-1,k}^{n+1}\} g(\rho_{gi,j-1,k}^{n+1} D_{i,j-1,k} - \rho_{gi,j,k}^{n+1} D_{i,j,k}) \Big]
\end{aligned} \tag{4.26}$$

$$\begin{aligned}
V_{k,j,k} \Delta_z (\rho_g v_{gz} T \sum_i (c_{p,i} T + L_{vi}) \frac{C_{i\alpha}}{f_{i\alpha g}})^{n+1} &= - \frac{A_z k_z k_{rg} \rho_g}{\mu_g \Delta z} |_{i,j,k}^{n+1} (s_{k+1} p_{oi,j,k+1}^{n+1} + s_k p_{oi,j,k}^{n+1} + s_{k-1} p_{oi,j,k-1}^{n+1} \\
& + s_{k+1} P_{cgo_{i,j,k+1}}^{n+1} + s_k P_{cgo_{i,j,k}}^{n+1} + s_{k-1} P_{cgo_{i,j,k-1}}^{n+1}
\end{aligned}$$

$$\begin{aligned}
& -s_{k+1}gD_{i,j,k+1}\rho_{g,i,j,k+1}^{n+1} - s_k gD_{i,j,k}\rho_{g,i,j,k}^{n+1} - s_{k-1}gD_{i,j,k-1}\rho_{g,i,j,k-1}^{n+1}) \\
& \cdot (s_{k+1} \sum_i (c_p, T + L_{vi}) \frac{C_{i_o}}{f_{i_o g}} |_{i,j,k+1}^{n+1} + s_k \sum_i (c_p, T + L_{vi}) \frac{C_{i_o}}{f_{i_o g}} |_{i,j,k}^{n+1} + s_{k-1} \sum_i (c_p, T + L_{vi}) \frac{C_{i_o}}{f_{i_o g}} |_{i,j,k-1}^{n+1}) \\
& - \sum_i (c_p, T + L_{vi}) \frac{C_{i_o}}{f_{i_o g}} |_{i,j,k}^{n+1} \left[\left\{ w_{g_s} \frac{A_z k_z k_{rg} \rho_g}{\mu_g \Delta z} |_{i,j,k}^{n+1} + (1 - w_{g_s}) \frac{A_z k_z k_{rg} \rho_g}{\mu_g \Delta z} |_{i,j,k+1}^{n+1} \right\} (p_{o,i,j,k+1}^{n+1} - p_{o,i,j,k}^{n+1}) \right. \\
& + \left\{ w_{g_s} \frac{A_z k_z k_{rg} \rho_g}{\mu_g \Delta z} |_{i,j,k}^{n+1} + (1 - w_{g_s}) \frac{A_z k_z k_{rg} \rho_g}{\mu_g \Delta z} |_{i,j,k+1}^{n+1} \right\} (P_{cgo,i,j,k+1}^{n+1} - P_{cgo,i,j,k}^{n+1}) \\
& - \left\{ w_{g_s}^* \frac{A_z k_z k_{rg} \rho_g}{\mu_g \Delta z} |_{i,j,k}^{n+1} + (1 - w_{g_s}^*) \frac{A_z k_z k_{rg} \rho_g}{\mu_g \Delta z} |_{i,j,k-1}^{n+1} \right\} (p_{o,i,j,k}^{n+1} - p_{o,i,j,k-1}^{n+1}) \\
& - \left\{ w_{g_s}^* \frac{A_z k_z k_{rg} \rho_g}{\mu_g \Delta z} |_{i,j,k}^{n+1} + (1 - w_{g_s}^*) \frac{A_z k_z k_{rg} \rho_g}{\mu_g \Delta z} |_{i,j,k-1}^{n+1} \right\} (P_{cgo,i,j,k}^{n+1} - P_{cgo,i,j,k-1}^{n+1}) \\
& - \left\{ w_{g_s} \frac{A_z k_z k_{rg} \rho_g}{\mu_g \Delta z} |_{i,j,k}^{n+1} + (1 - w_{g_s}) \frac{A_z k_z k_{rg} \rho_g}{\mu_g \Delta z} |_{i,j,k+1}^{n+1} \right\} g(\rho_{g,i,j,k+1}^{n+1} D_{i,j,k+1} - \rho_{g,i,j,k}^{n+1} D_{i,j,k}) \\
& \left. + \left\{ w_{g_s}^* \frac{A_z k_z k_{rg} \rho_g}{\mu_g \Delta z} |_{i,j,k}^{n+1} + (1 - w_{g_s}^*) \frac{A_z k_z k_{rg} \rho_g}{\mu_g \Delta z} |_{i,j,k-1}^{n+1} \right\} g(\rho_{g,i,j,k-1}^{n+1} D_{i,j,k-1} - \rho_{g,i,j,k}^{n+1} D_{i,j,k}) \right] \\
\end{aligned} \tag{4.27}$$

The derivation of the above approximation is given in Appendix A.

Mass Fraction Constraints

The sum of the mass fractions of each component in oleic, aqueous, and vapor phases is separately equal to 1, which can be stated as follows:

$$\sum_{i=1}^n C_{i_o} = 1 \tag{4.28}$$

$$\sum_{i=1}^n C_{i_w} = 1 \tag{4.29}$$

$$\sum_{i=1}^n C_{i_g} = 1 \tag{4.30}$$

Equations (4.29) and (4.30) can be written as follows:

$$\sum_{i=1}^n \frac{C_{i_o}}{f_{i_o w}} = 1 \tag{4.31}$$

$$\sum_{i=1}^n \frac{C_{i_o}}{f_{i_o g}} = 1 \tag{4.32}$$

For the simulator, it is more convenient to write the above equations in the following form:

$$H_{i,j,k} = \sum_{i=1}^n \frac{C_{i_o}}{f_{i_o w}} - 1 \quad (4.33)$$

$$I_{i,j,k} = \sum_{i=1}^n \frac{C_{i_o}}{f_{i_o g}} - 1 \quad (4.34)$$

Solution Scheme

At this point, we have nine nonlinear equations, which can be stated as follows:

$$F_{i,j,k} = 0 \quad (i = 1, 2, \dots, 5) \quad (4.35)$$

$$G_{i,j,k} = 0 \quad (4.36)$$

$$\sum_{i=1}^5 C_{i_o} = 1 \quad (4.37)$$

$$H_{i,j,k} = 0 \quad (4.38)$$

$$I_{i,j,k} = 0 \quad (4.39)$$

The unknowns in the above nine equations are $p_o, S_w, S_g, T, C_{1o}, C_{2o}, C_{3o}, C_{4o}$, and C_{5o} for blocks $(i, j, k), (i+1, j, k), (i-1, j, k), (i, j+1, k), (i, j-1, k), (i, j, k+1)$, and $(i, j, k-1)$, i.e. 63 unknowns.

The above nonlinear equations were solved by generalized Newtonian iteration, using a block matrix band algorithm. For this purpose, the above equations take the following form:

$$\begin{aligned} & \sum_{l=1}^7 \frac{\partial F_p}{\partial p_{o_l}} \delta p_{o_l} + \sum_{l=1}^7 \frac{\partial F_p}{\partial S_{w_l}} \delta S_{w_l} + \sum_{l=1}^7 \frac{\partial F_p}{\partial S_{g_l}} \delta S_{g_l} + \sum_{l=1}^7 \frac{\partial F_p}{\partial T_l} \delta T_l \\ & + \sum_{i=1}^5 \left(\sum_{l=1}^7 \frac{\partial F_p}{\partial C_{i_o l}} \delta C_{i_o l} \right) = -F_{p,i,j,k} \quad (p = 1, 2, \dots, 5) \end{aligned} \quad (4.40)$$

where $p=1,2,\dots,5$, represents each of the components.

$$\begin{aligned} & \sum_{i=1}^7 \frac{\partial G_p}{\partial p_{o_i}} \delta p_{o_i} + \sum_{i=1}^7 \frac{\partial G_p}{\partial S_{w_i}} \delta S_{w_i} + \sum_{i=1}^7 \frac{\partial G_p}{\partial S_{g_i}} \delta S_{g_i} + \sum_{i=1}^7 \frac{\partial G_p}{\partial T_i} \delta T_i \\ & + \sum_{i=1}^5 \left(\sum_{l=1}^7 \frac{\partial G_p}{\partial C_{i_o l}} \delta C_{i_o l} \right) = -G_{i,j,k} \end{aligned} \quad (4.41)$$

$$\frac{\partial H}{\partial p_o} \delta p_o + \frac{\partial H}{\partial T} \delta T + \sum_{i=1}^5 \frac{\partial H}{\partial C_{i_o}} \delta C_{i_o} \Big|_{i,j,k} = -H_{i,j,k} \quad (4.42)$$

$$\frac{\partial I}{\partial p_o} \delta p_o + \frac{\partial I}{\partial T} \delta T + \sum_{i=1}^5 \frac{\partial I}{\partial C_{i_o}} \delta C_{i_o} \Big|_{i,j,k} = -I_{i,j,k} \quad (4.43)$$

$$\sum_{i=1}^5 \delta C_{i_o} \Big|_{i,j,k} = 0 \quad (4.44)$$

$$H_{i,j,k} = \sum_{i=1}^5 \frac{C_{i_o}}{f_{i_o w}} - 1 \quad (4.45)$$

$$I_{i,j,k} = \sum_{i=1}^5 \frac{C_{i_o}}{f_{i_o g}} - 1 \quad (4.46)$$

Here l stands for blocks $(i, j, k-1)$, $(i, j-1, k)$, $(i-1, j, k)$, (i, j, k) , $(i+1, j, k)$, $(i, j+1, k)$, and $(i, j, k+1)$. Equations (4.44) to (4.46) involve only one particular block that can be (i, j, k) , $(i-1, j, k)$, etc. Therefore we can solve for C_{3o} , C_{4o} , and C_{5o} in terms of C_{1o} and C_{2o} , which are two of the nine main variables. The expressions for C_{3o} , C_{4o} , and C_{5o} are as follows:

$$\delta C_{3o} = (b_0 - C_{1o} a_0) + (b_1 - C_{1o} a_1) \delta C_{1o} + (b_2 - C_{1o} a_2) \delta C_{2o} + (b_3 - C_{1o} a_3) \delta p_o + (b_4 - C_{1o} a_4) \delta T \quad (4.47)$$

$$\delta C_{4o} = -\delta C_{1o} - \delta C_{2o} - \delta C_{3o} - \delta C_{5o} \quad (4.48)$$

$$\begin{aligned} \delta C_{5o} = & \left[\frac{H f_{4ow}}{\text{Den}_1 \left(1 - \frac{f_{4ow}}{f_{3ow}}\right)} \right] - \left[\frac{1 - \frac{f_{4ow}}{f_{1ow}}}{\text{Den}_1 \left(1 - \frac{f_{4ow}}{f_{3ow}}\right)} \right] \delta C_{1o} - \left[\frac{1 - \frac{f_{4ow}}{f_{2ow}}}{\text{Den}_1 \left(1 - \frac{f_{4ow}}{f_{3ow}}\right)} \right] \delta C_{2o} \\ & - \left[\frac{f_{4ow} \sum_{i=1}^5 \frac{C_{i_o}}{f_{i_o w}^2} \frac{\partial f_{4ow}}{\partial p_o}}{\text{Den}_1 \left(1 - \frac{f_{4ow}}{f_{3ow}}\right)} \right] \delta p_o - \left[\frac{f_{4ow} \sum_{i=1}^5 \frac{C_{i_o}}{f_{i_o w}^2} \frac{\partial f_{4ow}}{\partial T}}{\text{Den}_1 \left(1 - \frac{f_{4ow}}{f_{3ow}}\right)} \right] \delta T \end{aligned} \quad (4.49)$$

where

$$\text{Den}_1 = \frac{1 - \frac{f_{4ow}}{f_{3ow}}}{\left(1 - \frac{f_{4ow}}{f_{3ow}}\right)} - \frac{1 - \frac{f_{4og}}{f_{3og}}}{\text{Den}_2} \quad (4.50)$$

$$\text{Den}_2 = 1 - \frac{f_{4og}}{f_{3og}} \quad (4.51)$$

$$b_0 = If_{4og}/Den_2 \quad (4.52)$$

$$b_1 = (1 - \frac{f_{4og}}{f_{1og}})/Den_2 \quad (4.53)$$

$$b_2 = (1 - \frac{f_{4og}}{f_{2og}})/Den_2 \quad (4.54)$$

$$b_3 = f_{4og} \sum_{i=1}^5 \frac{C_{i_g}}{f_{iog}^2} \frac{\partial f_{iog}}{\partial p_o} / Den_2 \quad (4.55)$$

$$b_4 = f_{4og} \sum_{i=1}^5 \frac{C_{i_g}}{f_{iog}^2} \frac{\partial f_{iog}}{\partial T} / Den_2 \quad (4.56)$$

$$c_1 = (1 - \frac{f_{4og}}{f_{5og}})/Den_2 \quad (4.57)$$

$$Den_3 = (1 - \frac{f_{4ow}}{f_{3ow}}) \cdot Den_1 \quad (4.58)$$

$$a_0 = Hf_{4ow}/Den_3 \quad (4.59)$$

$$a_1 = (1 - \frac{f_{4ow}}{f_{1ow}})/Den_3 \quad (4.60)$$

$$a_2 = (1 - \frac{f_{4ow}}{f_{2ow}})/Den_3 \quad (4.61)$$

$$a_3 = f_{4ow} \sum_{i=1}^5 \frac{C_{i_w}}{f_{iow}^2} \frac{\partial f_{iow}}{\partial p_o} / Den_3 \quad (4.62)$$

$$a_4 = f_{4ow} \sum_{i=1}^5 \frac{C_{i_w}}{f_{iow}^2} \frac{\partial f_{iow}}{\partial T} / Den_3 \quad (4.63)$$

Substituting the above in Eqs.(4.40) through (4.46), six equations in six unknowns p_o, S_w, S_g, T, C_{1o} , and C_{2o} are obtained. The first five equations are given by

$$\delta u_i = u_i^{n+1(m+1)} - u_i^{n+1(m)},$$

where u stands for any of the six variables, n is the time level, and (m) is the iteration level. A convenient notation for the aforesaid six equations is

$$\begin{aligned} & Z^{p,1}_{i,j,k} \delta p_{oi,j,k-1} + B^{p,1}_{i,j,k} \delta p_{oi,j-1,k} + D^{p,1}_{i,j,k} \delta p_{oi-1,j,k} + E^{p,1}_{i,j,k} \delta p_{oi,j,k} \\ & + F^{p,1}_{i,j,k} \delta p_{oi+1,j,k} + H^{p,1}_{i,j,k} \delta p_{oi,j+1,k} + S^{p,1}_{i,j,k} \delta p_{oi,j,k+1} \\ & + Z^{p,2}_{i,j,k} \delta S_{wi,j,k-1} + B^{p,2}_{i,j,k} \delta S_{wi,j-1,k} + D^{p,2}_{i,j,k} \delta S_{wi-1,j,k} + E^{p,2}_{i,j,k} \delta S_{wi,j,k} \\ & + F^{p,2}_{i,j,k} \delta S_{wi+1,j,k} + H^{p,2}_{i,j,k} \delta S_{wi,j+1,k} + S^{p,2}_{i,j,k} \delta S_{wi,j,k+1} \\ & + Z^{p,3}_{i,j,k} \delta S_{gi,j,k-1} + B^{p,3}_{i,j,k} \delta S_{gi,j-1,k} + D^{p,3}_{i,j,k} \delta S_{gi-1,j,k} + E^{p,3}_{i,j,k} \delta S_{gi,j,k} \\ & + F^{p,3}_{i,j,k} \delta S_{gi+1,j,k} + H^{p,3}_{i,j,k} \delta S_{gi,j+1,k} + S^{p,3}_{i,j,k} \delta S_{gi,j,k+1} \\ & + Z^{p,4}_{i,j,k} \delta T_{i,j,k-1} + B^{p,4}_{i,j,k} \delta T_{i,j-1,k} + D^{p,4}_{i,j,k} \delta T_{i-1,j,k} + E^{p,4}_{i,j,k} \delta T_{i,j,k} \\ & + F^{p,4}_{i,j,k} \delta T_{i+1,j,k} + H^{p,4}_{i,j,k} \delta T_{i,j+1,k} + S^{p,4}_{i,j,k} \delta T_{i,j,k+1} \\ & + Z^{p,5}_{i,j,k} \delta C_{1oi,j,k-1} + B^{p,5}_{i,j,k} \delta C_{1oi,j-1,k} + D^{p,5}_{i,j,k} \delta C_{1oi-1,j,k} + E^{p,5}_{i,j,k} \delta C_{1oi,j,k} \\ & + F^{p,5}_{i,j,k} \delta C_{1oi+1,j,k} + H^{p,5}_{i,j,k} \delta C_{1oi,j+1,k} + S^{p,5}_{i,j,k} \delta C_{1oi,j,k+1} \\ & + Z^{p,6}_{i,j,k} \delta C_{2oi,j,k-1} + B^{p,6}_{i,j,k} \delta C_{2oi,j-1,k} + D^{p,6}_{i,j,k} \delta C_{2oi-1,j,k} + E^{p,6}_{i,j,k} \delta C_{2oi,j,k} \\ & + F^{p,6}_{i,j,k} \delta C_{2oi+1,j,k} + H^{p,6}_{i,j,k} \delta C_{2oi,j+1,k} + S^{p,6}_{i,j,k} \delta C_{2oi,j,k+1} = Q^p_{i,j,k}, \end{aligned}$$

where $p = 1, 2, \dots, 5$ stands for the five component mass balances, Eq. (4.64), and $p = 6$ corresponds to the energy balance Eq. (4.65). A more stable formulation results if the variables are eliminated at the matrix level. This is same as solving for all nine unknowns, without eliminating three unknowns as done previously.

Derivatives of the Mass Balance Equation

The fully implicit scheme used in this work leads to nonlinear equations. The Newtonian iteration scheme is used to linearize the mass balance and heat balance equations. For this purpose, the derivatives of the mass balance equation $F_{i,j,k} = 0$, and the heat balance equation $G_{i,j,k} = 0$ need to be obtained. The derivatives of $F_{i,j,k}$ are taken with respect to p_o, S_w, S_g, T , and C_{i_o} , ($i = 1, 2, \dots, 5$), at points $(i, j, k - 1)$, $(i, j - 1, k)$, $(i - 1, j, k)$, (i, j, k) , $(i + 1, j, k)$, $(i, j + 1, k)$, and $(i, j, k + 1)$. All derivatives, except those at (i, j, k) were obtained analytically. The latter derivatives were computed numerically, because the analytical derivative expressions were very long, and tests showed that the analytical derivative took much longer to calculate than the numerical derivative.

The analytical derivatives of the F_i function are given in the following, only for the block $(i+1, j, k)$. The derivatives at the other five blocks $(i, j, k-1)$, $(i, j-1, k)$, $(i-1, j, k)$, $(i, j+1, k)$, and $(i, j, k+1)$ were obtained by interchanging the subscripts. This has to be done rather carefully because some of the subscripts may remain invariant under such a scheme.

Derivative of F_i with respect to p_o

$$\begin{aligned}
 \frac{\partial F_i}{\partial p_o} \Big|_{i+1,j,k} &= \frac{A_x k_x}{\Delta x} \Big|_{i+\frac{1}{2},j,k}^{n+1} \left\{ w_{o_s} \frac{k_{ro} \rho_o C_{i_s}}{\mu_o} \Big|_{i,j,k} + (1-w_{o_s}) \frac{k_{ro} \rho_o C_{i_s}}{\mu_o} \Big|_{i+1,j,k} + w_{w_s} \frac{k_{rw} \rho_w C_{i_s}}{\mu_w f_{iow}} \Big|_{i,j,k} \right. \\
 &\quad \left. + (1-w_{w_s}) \frac{k_{rw} \rho_w C_{i_s}}{\mu_w f_{iow}} \Big|_{i+1,j,k} + w_{g_s} \frac{k_{rg} \rho_g C_{i_s}}{\mu_g f_{iog}} \Big|_{i,j,k} + (1-w_{g_s}) \frac{k_{rg} \rho_g C_{i_s}}{\mu_g f_{iog}} \Big|_{i+1,j,k} \right\} \\
 &+ \frac{A_x k_x}{\Delta x} \Big|_{i+\frac{1}{2},j,k}^{n+1} \left\{ (1-w_{o_s}) \left(\frac{k_{ro} C_{i_s}}{\mu_o} \frac{\partial \rho_o}{\partial p_o} \right) \Big|_{i,j,k} + (1-w_{w_s}) \frac{k_{rw} C_{i_s}}{\mu_w} \left(\frac{1}{f_{iow}} \frac{\partial \rho_w}{\partial p_o} - \frac{\rho_w}{f_{iow}^2} \frac{\partial f_{iow}}{\partial p_o} \right) \Big|_{i,j,k} \right. \\
 &\quad \left. + (1-w_{g_s}) \frac{k_{rg} C_{i_s}}{\mu_g} \left(\frac{1}{f_{iog}} \frac{\partial \rho_g}{\partial p_o} - \frac{\rho_g}{f_{iog}^2} \frac{\partial f_{iog}}{\partial p_o} \right) \Big|_{i,j,k} \right\} (p_{o,+1,j,k} - p_{o,j,k}) \\
 &+ \frac{A_x k_x}{\Delta x} \Big|_{i+\frac{1}{2},j,k}^{n+1} \left\{ 2(1-w_{o_s}) g \left(\frac{k_{ro} \rho_o C_{i_s}}{\mu_o} \frac{\partial \rho_o}{\partial p_o} \right) \Big|_{i+1,j,k} + (1-w_{w_s}) g \frac{k_{rw} C_{i_s}}{\mu_w} \left(\frac{2\rho_w}{f_{iow}} \frac{\partial \rho_w}{\partial p_o} - \frac{\rho_w^2}{f_{iow}^2} \frac{\partial f_{iow}}{\partial p_o} \right) \Big|_{i+1,j,k} \right. \\
 &\quad \left. + (1-w_{g_s}) g \frac{k_{rg} C_{i_s}}{\mu_g} \left(\frac{2\rho_g}{f_{iog}} \frac{\partial \rho_g}{\partial p_o} - \frac{\rho_g^2}{f_{iog}^2} \frac{\partial f_{iog}}{\partial p_o} \right) \Big|_{i+1,j,k} \right\} (D_{+,j,k} - D_{-,j,k}) \\
 &+ \frac{A_x k_x}{\Delta x} \Big|_{i+\frac{1}{2},j,k}^{n+1} (1-w_{w_s}) \frac{k_{rw} C_{i_s}}{\mu_w} \left(\frac{1}{f_{iow}} \frac{\partial \rho_w}{\partial p_o} - \frac{\rho_w}{f_{iow}^2} \frac{\partial f_{iow}}{\partial p_o} \right) \Big|_{i+1,j,k} (P_{cow,j,k} - P_{cow,+1,j,k}) \\
 &+ \frac{A_x k_x}{\Delta x} \Big|_{i+\frac{1}{2},j,k}^{n+1} (1-w_{g_s}) \frac{k_{rg} C_{i_s}}{\mu_g} \left(\frac{1}{f_{iog}} \frac{\partial \rho_g}{\partial p_o} - \frac{\rho_g}{f_{iog}^2} \frac{\partial f_{iog}}{\partial p_o} \right) \Big|_{i+1,j,k} (P_{cgo,j,k} - P_{cgo,+1,j,k}) \\
 &+ \frac{A_x D_{io} C_{i_s}}{\Delta x} \frac{\partial \rho_o}{\partial p_o} \Big|_{i+1,j,k} + \frac{A_x D_{iw} C_{i_s}}{\Delta x} \frac{k_{rw} C_{i_s}}{\mu_w} \left(\frac{1}{f_{iow}} \frac{\partial \rho_w}{\partial p_o} - \frac{\rho_w}{f_{iow}^2} \frac{\partial f_{iow}}{\partial p_o} \right) \Big|_{i+1,j,k} \\
 &\quad + \frac{A_x D_{ig} C_{i_s}}{\Delta x} \frac{k_{rg} C_{i_s}}{\mu_g} \left(\frac{1}{f_{iog}} \frac{\partial \rho_g}{\partial p_o} - \frac{\rho_g}{f_{iog}^2} \frac{\partial f_{iog}}{\partial p_o} \right) \Big|_{i+1,j,k}
 \end{aligned} \tag{4.66}$$

Derivative of F_i with respect to S_w

$$\begin{aligned}
 \frac{\partial F_i}{\partial S_w} \Big|_{i+1,j,k} &= \frac{A_x k_x}{\Delta x} \Big|_{i+\frac{1}{2},j,k}^{n+1} \left\{ (1-w_{o_s}) \frac{\rho_o C_{i_s}}{\mu_o} \frac{\partial k_{ro}}{\partial S_w} \Big|_{i+1,j,k} [(p_{o,+1,j,k}^{n+1} - p_{o,j,k}^{n+1}) \right. \\
 &\quad \left. - \rho_{o,+1,j,k} g (D_{+,j,k} - D_{-,j,k})] + (1-w_{w_s}) \left(\frac{k_{rw} C_{i_s}}{\mu_w} \frac{\partial \rho_w}{\partial p_o} \right) \Big|_{i+1,j,k} \right. \\
 &\quad \left. - [(p_{o,+1,j,k}^{n+1} - p_{o,j,k}^{n+1}) - \rho_{o,+1,j,k} g (D_{+,j,k} - D_{-,j,k}) - (P_{cow,+1,j,k} - P_{cow,j,k})] \right\} \\
 &\quad - T_{w_s,+1,j,k} \frac{\partial P_{cow}}{\partial S_w} \Big|_{i+1,j,k}
 \end{aligned} \tag{4.67}$$

Derivative of F_i with respect to S_g

$$\frac{\partial F_i}{\partial S_g} \Big|_{i+1,j,k} = \frac{A_x k_x}{\Delta x} \Big|_{i+\frac{1}{2},j,k}^{n+1} \left\{ (1-w_{o_s}) \frac{\rho_o C_{i_s}}{\mu_o} \frac{\partial k_{ro}}{\partial S_g} \Big|_{i+1,j,k} [(p_{o,+1,j,k}^{n+1} - p_{o,j,k}^{n+1}) \right.$$

$$\begin{aligned}
& -\rho_{o,i+1,j,k} g(D_{i+1,j,k} - D_{i,j,k}) + (1 - w_{g_s}) \left(\frac{k_{rg} C_{i_o}}{\mu_g} \frac{\partial \rho_g}{\partial p_o} \right)_{i+1,j,k} \\
& \cdot [(p_{o,i+1,j,k}^{n+1} - p_{o,i,j,k}^{n+1}) - \rho_{g,i+1,j,k} g(D_{i+1,j,k} - D_{i,j,k}) - (P_{cgo,i+1,j,k} - P_{cgo,i,j,k})] \\
& - T_{gs,i+\frac{1}{2},j,k} \frac{\partial P_{cgo}}{\partial S_g} \Big|_{i+1,j,k}
\end{aligned} \quad (4.68)$$

Derivative of F_i with respect to T

$$\begin{aligned}
& \frac{A_x k_x}{\Delta x} \Big|_{i+\frac{1}{2},j,k}^{n+1} \{ (1 - w_{o_s}) \left[\frac{k_{ro} C_{i_o}}{\mu_o} \frac{\partial \rho_o}{\partial T} \Big|_{i+1,j,k} + \frac{\rho_o C_{i_o}}{\mu_o} \frac{\partial k_{ro}}{\partial T} \Big|_{i+1,j,k} - \frac{k_{ro} \rho_o C_{i_o}}{\mu_o^2} \frac{\partial \mu_o}{\partial T} \Big|_{i+1,j,k} \right] \right. \\
& + (1 - w_{w_s}) \left[\frac{k_{rw} C_{i_o}}{\mu_w f_{iow}} \frac{\partial \rho_w}{\partial T} \Big|_{i+1,j,k} + \frac{\rho_w C_{i_o}}{\mu_w f_{iow}} \frac{\partial k_{rw}}{\partial T} \Big|_{i+1,j,k} - \frac{k_{rw} \rho_w C_{i_o}}{\mu_w^2 f_{iow}} \frac{\partial \mu_w}{\partial T} \Big|_{i+1,j,k} - \frac{k_{rw} \rho_w C_{i_o}}{\mu_w f_{iow}^2} \frac{\partial f_{iow}}{\partial T} \Big|_{i+1,j,k} \right] \\
& \left. + (1 - w_{g_s}) \left[\frac{k_{rg} C_{i_o}}{\mu_g f_{iog}} \frac{\partial \rho_g}{\partial T} \Big|_{i+1,j,k} + \frac{\rho_g C_{i_o}}{\mu_g f_{iog}} \frac{\partial k_{rg}}{\partial T} \Big|_{i+1,j,k} - \frac{k_{rg} \rho_g C_{i_o}}{\mu_g^2 f_{iog}} \frac{\partial \mu_g}{\partial T} \Big|_{i+1,j,k} - \frac{k_{rg} \rho_g C_{i_o}}{\mu_g f_{iog}^2} \frac{\partial f_{iog}}{\partial T} \Big|_{i+1,j,k} \right] \} \\
& \cdot (p_{o,i+1,j,k} - p_{o,i,j,k}) - \frac{A_x k_x}{\Delta x} \Big|_{i+\frac{1}{2},j,k}^{n+1} \{ (1 - w_{w_s}) \left[\frac{k_{rw} C_{i_o}}{\mu_w f_{iow}} \frac{\partial \rho_w}{\partial T} \Big|_{i+1,j,k} + \frac{\rho_w C_{i_o}}{\mu_w f_{iow}} \frac{\partial k_{rw}}{\partial T} \Big|_{i+1,j,k} - \frac{k_{rw} \rho_w C_{i_o}}{\mu_w^2 f_{iow}} \frac{\partial \mu_w}{\partial T} \Big|_{i+1,j,k} \right. \right. \\
& \left. \left. - \frac{k_{rw} \rho_w C_{i_o}}{\mu_w f_{iow}^2} \frac{\partial f_{iow}}{\partial T} \Big|_{i+1,j,k} \right] (P_{cwo,i+1,j,k} - P_{cwo,i,j,k}) + (1 - w_{g_s}) \right. \\
& \left. \left[\frac{k_{rg} C_{i_o}}{\mu_g f_{iog}} \frac{\partial \rho_g}{\partial T} \Big|_{i+1,j,k} + \frac{\rho_g C_{i_o}}{\mu_g f_{iog}} \frac{\partial k_{rg}}{\partial T} \Big|_{i+1,j,k} - \frac{k_{rg} \rho_g C_{i_o}}{\mu_g^2 f_{iog}} \frac{\partial \mu_g}{\partial T} \Big|_{i+1,j,k} - \frac{k_{rg} \rho_g C_{i_o}}{\mu_g f_{iog}^2} \frac{\partial f_{iog}}{\partial T} \Big|_{i+1,j,k} \right] (P_{cgo,i+1,j,k} - P_{cgo,i,j,k}) \right. \\
& \left. + [(1 - w_{g_s}) \frac{k_{rg} \rho_g C_{i_o}}{\mu_g f_{iog}} \Big|_{i+1,j,k} + w_{g_s} \frac{k_{rg} \rho_g C_{i_o}}{\mu_g f_{iog}} \Big|_{i,j,k}] \frac{\partial P_{cgo}}{\partial T} \Big|_{i+1,j,k} \right\} \\
& + \frac{A_x D_{i_o}}{\Delta x} \Big|_{i+\frac{1}{2},j,k}^{n+1} C_{i_o,i+1,j,k} \frac{\partial \rho_o}{\partial T} \Big|_{i+1,j,k} + \frac{A_x D_{i_w}}{\Delta x} \left[\frac{C_{i_o}}{f_{iow,i+1,j,k}} - \left(-\frac{\rho_o C_{i_o}}{f_{iow}^2} \frac{\partial f_{iow}}{\partial T} \right)_{i+1,j,k} \right] \\
& + \frac{A_x D_{i_g}}{\Delta x} \left[\frac{C_{i_o}}{f_{iog,i+1,j,k}} - \left(-\frac{\rho_g C_{i_o}}{f_{iog}^2} \frac{\partial f_{iog}}{\partial T} \right)_{i+1,j,k} \right]
\end{aligned} \quad (4.69)$$

Derivative of F_i with respect to C_{i_o}

$$\begin{aligned}
\frac{\partial F_{i,j,k}}{\partial C_{i_o,i+1,j,k}} &= \frac{A_x k_x}{\Delta x} \Big|_{i+\frac{1}{2},j,k}^{n+1} \{ (1 - w_{o_s}) k_{ro,i+1,j,k} \left[\frac{\rho_o}{\mu_o} \Big|_{i+1,j,k} - \frac{\rho_o C_{i_o}}{\mu_o^2} \frac{\partial \mu_o}{\partial C_{i_o}} \Big|_{i+1,j,k} + \frac{C_{i_o}}{\mu_o} \frac{\partial \rho_o}{\partial C_{i_o}} \Big|_{i+1,j,k} \right] \right. \\
& + (1 - w_{w_s}) \frac{k_{rw}}{f_{iow}} \left[\frac{\rho_w}{\mu_w} \Big|_{i+1,j,k} - \frac{\rho_w C_{i_o}}{\mu_w^2} \frac{\partial \mu_w}{\partial C_{i_o}} \Big|_{i+1,j,k} + \frac{C_{i_o}}{\mu_w} \frac{\partial \rho_w}{\partial C_{i_o}} \Big|_{i+1,j,k} \right] \\
& \left. + (1 - w_{g_s}) \frac{k_{rg}}{f_{iog}} \left[\frac{\rho_g}{\mu_g} \Big|_{i+1,j,k} - \frac{\rho_g C_{i_o}}{\mu_g^2} \frac{\partial \mu_g}{\partial C_{i_o}} \Big|_{i+1,j,k} + \frac{C_{i_o}}{\mu_g} \frac{\partial \rho_g}{\partial C_{i_o}} \Big|_{i+1,j,k} \right] \} (p_{o,i+1,j,k}^{n+1} - p_{o,i,j,k}^{n+1}) \\
& - \frac{A_x k_x}{\Delta x} \Big|_{i+\frac{1}{2},j,k}^{n+1} \{ (1 - w_{o_s}) k_{ro,i+1,j,k} g \left[\frac{\rho_o}{\mu_o} \Big|_{i+1,j,k} - \rho_o^2 C_{i_o} \Big|_{i+1,j,k} \frac{1}{\mu_o^2} \frac{\partial \mu_o}{\partial C_{i_o}} \Big|_{i+1,j,k} + \frac{2\rho_o C_{i_o}}{\mu_o} \frac{\partial \rho_o}{\partial C_{i_o}} \Big|_{i+1,j,k} \right] \right. \\
& + (1 - w_{w_s}) \frac{k_{rw}}{f_{iow,i+1,j,k}} g \left[\frac{\rho_w^2}{\mu_w} \Big|_{i+1,j,k} - \rho_w^2 C_{i_o} \Big|_{i+1,j,k} \frac{1}{\mu_w^2} \frac{\partial \mu_w}{\partial C_{i_o}} \Big|_{i+1,j,k} + \frac{2\rho_w C_{i_o}}{\mu_w} \frac{\partial \rho_w}{\partial C_{i_o}} \Big|_{i+1,j,k} \right] \\
& \left. + (1 - w_{g_s}) \frac{k_{rg}}{f_{iog,i+1,j,k}} g \left[\frac{\rho_g^2}{\mu_g} \Big|_{i+1,j,k} - \rho_g^2 C_{i_o} \Big|_{i+1,j,k} \frac{1}{\mu_g^2} \frac{\partial \mu_g}{\partial C_{i_o}} \Big|_{i+1,j,k} + \frac{2\rho_g C_{i_o}}{\mu_g} \frac{\partial \rho_g}{\partial C_{i_o}} \Big|_{i+1,j,k} \right] \} (D_{i+1,j,k} - D_{i,j,k}) \right. \\
& \left. - \{ (1 - w_{w_s}) \frac{k_{rw}}{f_{iow}} \left[\frac{\rho_w}{\mu_w} \Big|_{i+1,j,k} - \frac{\rho_w C_{i_o}}{\mu_w^2} \frac{\partial \mu_w}{\partial C_{i_o}} \Big|_{i+1,j,k} + \frac{C_{i_o}}{\mu_w} \frac{\partial \rho_w}{\partial C_{i_o}} \Big|_{i+1,j,k} \right] (P_{cwo,i+1,j,k} - P_{cwo,i,j,k}) \right.
\end{aligned}$$

$$\begin{aligned}
& + (1 - w_{gs}) \left[\frac{k_{rg}}{f_{iog}} \left| \frac{\rho_g}{\mu_g} \right|_{i+1,j,k} - \frac{\rho_g C_{i_g}}{\mu_g^2} \frac{\partial \mu_g}{\partial C_{i_g}} \right|_{i+1,j,k} + \frac{C_{i_g}}{\mu_g} \frac{\partial \rho_g}{\partial C_{i_g}} \right|_{i+1,j,k} \right] (P_{eg0,i+1,j,k} - P_{eg0,i,j,k}) \\
& + \frac{A_x D_{io}}{\Delta x} \left[\rho_{o,i+1,j,k} + C_{i_o} \frac{\partial \rho_o}{\partial C_{i_o}} \right|_{i+1,j,k} \\
& + \frac{A_x D_{iw}}{\Delta x} \frac{1}{f_{iow}} \left|_{i+1,j,k} \left[\frac{\rho_w}{\mu_w} \right|_{i+1,j,k} - \frac{\rho_w C_{i_o}}{\mu_w^2} \frac{\partial \mu_w}{\partial C_{i_o}} \right|_{i+1,j,k} + \frac{C_{i_o}}{\mu_w} \frac{\partial \rho_w}{\partial C_{i_o}} \right|_{i+1,j,k} \right] \\
& + \frac{A_x D_{ig}}{\Delta x} \frac{1}{f_{iog}} \left|_{i+1,j,k} \left[\frac{\rho_g}{\mu_g} \right|_{i+1,j,k} - \frac{\rho_g C_{i_g}}{\mu_g^2} \frac{\partial \mu_g}{\partial C_{i_g}} \right|_{i+1,j,k} + \frac{C_{i_g}}{\mu_g} \frac{\partial \rho_g}{\partial C_{i_g}} \right|_{i+1,j,k} \right] \quad (4.70)
\end{aligned}$$

Derivatives of the Energy Balance Equation

Derivatives of the energy balance equation $G_{i,j,k} = 0$ were obtained in a manner similar to the mass balance equations. These are given below:

Derivative of G with respect to p_o

$$\begin{aligned}
\frac{\partial G_{i,j,k}}{\partial p_{oi+1,j,k}} &= \frac{A_x k_x k_{ro} \rho_w}{\mu_o \Delta x} \Big|_{i,j,k} (s_{i+1} - s_{i+1} g D_{i+1,j,k} \frac{\partial \rho_o}{\partial p_o} \Big|_{i+1,j,k}) \\
&\cdot (s_{i+1} T_{i+1,j,k} \sum_i (c_p, C_{i_o}) \Big|_{i+1,j,k} + s_i T k j i \sum_i (c_p, C_{i_o}) \Big|_{i,j,k} + s_{i-1} T_{i-1,j,k} \sum_i (c_p, C_{i_o}) \Big|_{i-1,j,k}) \\
&+ T_{i,j,k} \sum_i (c_p, C_{i_o}) \Big|_{i,j,k} \{ (w_{os} \frac{A_x k_x k_{ro} \rho_w}{\mu_o \Delta x} \Big|_{i,j,k} + (1 - w_{os}) \frac{A_x k_x k_{ro} \rho_w}{\mu_o \Delta x} \Big|_{i+1,j,k}) \\
&\quad + (1 - w_{os}) \frac{A_x k_x k_{ro} \rho_w}{\mu_o \Delta x} \Big|_{i+1,j,k} \frac{\partial \rho_o}{\partial p_o} \Big|_{i+1,j,k} (p_{o,i+1,j,k}^{n+1} - p_{o,i,j,k}^{n+1}) \\
&\quad - (w_{os} \frac{A_x k_x k_{ro} \rho_w}{\mu_o \Delta x} \Big|_{i,j,k} + (1 - w_{os}) \frac{A_x k_x k_{ro} \rho_w}{\mu_o \Delta x} \Big|_{i+1,j,k}) \frac{\partial \rho_o}{\partial p_o} \Big|_{i+1,j,k} g D_{i+1,j,k} \\
&\quad - (1 - w_{os}) \frac{A_x k_x k_{ro} \rho_w}{\mu_o \Delta x} \Big|_{i+1,j,k} \frac{\partial \rho_o}{\partial p_o} \Big|_{i+1,j,k} g (\rho_{oi+1,j,k} D_{i+1,j,k} - \rho_{oi,j,k}^{n+1} D_{i,j,k}) \} \\
&\quad + \frac{A_x k_x k_{rw} \rho_w}{\mu_w \Delta x} \Big|_{i,j,k} (s_{i+1} - s_{i+1} g D_{i+1,j,k} \frac{\partial \rho_w}{\partial p_o} \Big|_{i+1,j,k}) \\
&\cdot (s_{i+1} T_{i+1,j,k}^{n+1} \sum_i (c_p, \frac{C_{i_o}}{f_{iow}}) \Big|_{i+1,j,k}^{n+1} + s_i T_{i,j,k}^{n+1} \sum_i (c_p, \frac{C_{i_o}}{f_{iow}}) \Big|_{i,j,k}^{n+1} + s_{i-1} T_{i-1,j,k}^{n+1} \sum_i (c_p, \frac{C_{i_o}}{f_{iow}}) \Big|_{i-1,j,k}^{n+1}) \\
&\quad + \frac{A_x k_x k_{rw} \rho_w}{\mu_w \Delta x} \Big|_{i,j,k} (s_{i+1} p_{oi+1,j,k}^{n+1} + s_i p_{oi,j,k}^{n+1} + s_{i-1} p_{oi-1,j,k}^{n+1} \\
&\quad - s_{i+1} P_{cow,i+1,j,k}^{n+1} - s_i P_{cow,i,j,k}^{n+1} + s_{i-1} P_{cow,i-1,j,k}^{n+1} \\
&\quad - s_{i+1} g D_{i+1,j,k} \rho_{w,i+1,j,k}^{n+1} - s_i g D_{i,j,k} \rho_{w,i,j,k}^{n+1} - s_{i-1} g D_{i-1,j,k} \rho_{w,i-1,j,k}^{n+1}) \\
&\quad \cdot (s_{i+1} T_{i+1,j,k} \sum_i (c_p, (-\frac{C_{i_o}}{f_{iow}^2} \frac{\partial f_{iow}}{\partial p_o}) \Big|_{i+1,j,k}) \\
&T_{i,j,k} \sum_i (c_p, \frac{C_{i_o}}{f_{iow}}) \Big|_{i,j,k} \{ (w_{os} \frac{A_x k_x k_{rw} \rho_w}{\mu_w \Delta x} \Big|_{i,j,k} + (1 - w_{os}) \frac{A_x k_x k_{rw} \rho_w}{\mu_w \Delta x} \Big|_{i+1,j,k}) \\
&\quad + (1 - w_{os}) \frac{A_x k_x k_{rw} \rho_w}{\mu_w \Delta x} \Big|_{i+1,j,k} \frac{\partial \rho_w}{\partial p_o} \Big|_{i+1,j,k} (p_{o,i+1,j,k}^{n+1} - p_{o,i,j,k}^{n+1})
\end{aligned}$$

$$\begin{aligned}
& -(1-w_{w_s}) \frac{A_x k_x k_{rw} \rho_w}{\mu_w \Delta x} \Big|_{i+1,j,k} \frac{\partial \rho_w}{\partial p_o} \Big|_{i+1,j,k} (P_{cow}^{n+1} - P_{cow}^{n+1}) \\
& -(w_{o_s} \frac{A_x k_x k_{rw} \rho_w}{\mu_w \Delta x} \Big|_{i,j,k} + (1-w_{w_s}) \frac{A_x k_x k_{rw} \rho_w}{\mu_w \Delta x} \Big|_{i+1,j,k}) \frac{\partial \rho_w}{\partial p_o} \Big|_{i+1,j,k} g D_{i+1,j,k} \\
& -(1-w_{w_s}) \frac{A_x k_x k_{rw} \rho_w}{\mu_w \Delta x} \Big|_{i+1,j,k} \frac{\partial \rho_w}{\partial p_o} \Big|_{i+1,j,k} g (\rho_{wi+1,j,k} D_{i+1,j,k} - \rho_{wi,j,k}^{n+1} D_{i,j,k}) \\
& + \frac{A_x k_x k_{rg} \rho_w}{\mu_g \Delta x} \Big|_{i,j,k} (s_{i+1} - s_{i+1} g D_{i+1,j,k} \frac{\partial \rho_g}{\partial p_o} \Big|_{i+1,j,k}) \\
& \cdot (s_{i+1} \sum_i (c_p T + L_{vi}) \frac{C_{i_2}}{f_{iog}} \Big|_{i+1,j,k}^{n+1} + s_i \sum_i (c_p T + L_{vi}) \frac{C_{i_2}}{f_{iog}} \Big|_{i,j,k}^{n+1} + s_{i-1} \sum_i (c_p T + L_{vi}) \frac{C_{i_2}}{f_{iog}} \Big|_{i-1,j,k}^{n+1}) \\
& + \frac{A_x k_x k_{rg} \rho_w}{\mu_g \Delta x} \Big|_{i,j,k} (s_{i+1} p_{oi+1,j,k}^{n+1} + s_i p_{oi,j,k}^{n+1} + s_{i-1} p_{oi-1,j,k}^{n+1} \\
& + s_{i+1} P_{cgoi+1,j,k}^{n+1} + s_i P_{cgoi,j,k}^{n+1} + s_{i-1} P_{cgoi-1,j,k}^{n+1} \\
& - s_{i+1} g D_{i+1,j,k} \rho_{gi+1,j,k}^{n+1} - s_i g D_{i,j,k} \rho_{gi,j,k}^{n+1} - s_{i-1} g D_{i-1,j,k} \rho_{gi-1,j,k}^{n+1}) \\
& \cdot (s_{i+1} \sum_i ((T_{i+1,j,k} c_p + L_{vi}) (-\frac{C_{i_2}}{f_{iog}^2} \frac{\partial f_{iog}}{\partial p_o}) \Big|_{i+1,j,k})) \\
& \sum_i (c_p T + L_{vi}) \frac{C_{i_2}}{f_{iog}} \Big|_{i,j,k} \{ (w_{g_s} \frac{A_x k_x k_{rg} \rho_w}{\mu_g \Delta x} \Big|_{i,j,k} + (1-w_{g_s}) \frac{A_x k_x k_{rg} \rho_w}{\mu_g \Delta x} \Big|_{i+1,j,k}) \\
& + (1-w_{g_s}) \frac{A_x k_x k_{rg} \rho_w}{\mu_g \Delta x} \Big|_{i+1,j,k} \frac{\partial \rho_g}{\partial p_o} \Big|_{i+1,j,k} (p_{o_s}^{n+1} - p_{o_s}^{n+1}) \\
& + (1-w_{g_s}) \frac{A_x k_x k_{rg} \rho_w}{\mu_g \Delta x} \Big|_{i+1,j,k} \frac{\partial \rho_g}{\partial p_o} \Big|_{i+1,j,k} (P_{cgo}^{n+1} - P_{cgo}^{n+1}) \\
& - (w_{g_s} \frac{A_x k_x k_{rg} \rho_w}{\mu_g \Delta x} \Big|_{i,j,k} + (1-w_{g_s}) \frac{A_x k_x k_{rg} \rho_w}{\mu_g \Delta x} \Big|_{i+1,j,k}) \frac{\partial \rho_g}{\partial p_o} \Big|_{i+1,j,k} g D_{i+1,j,k} \\
& - (1-w_{g_s}) \frac{A_x k_x k_{rg} \rho_w}{\mu_g \Delta x} \Big|_{i+1,j,k} \frac{\partial \rho_g}{\partial p_o} \Big|_{i+1,j,k} g (\rho_{gi+1,j,k} D_{i+1,j,k} - \rho_{gi,j,k}^{n+1} D_{i,j,k}) \\
& + \frac{A_x}{\Delta x} \Big|_{i+\frac{1}{2},j,k} \{ (1-w_{o_s}) \frac{\partial \rho_o}{\partial p_o} \Big|_{i+1,j,k} \sum_i [T c_{pi} D_{io} \Big|_{i+1,j,k}^{n+1} (C_{io}^{n+1} - C_{io}^{n+1})] \\
& (1-w_{w_s}) \frac{\partial \rho_w}{\partial p_o} \Big|_{i+1,j,k} \sum_i [T c_{pi} D_{iw} \Big|_{i+1,j,k}^{n+1} (\frac{C_{i_2}}{f_{iow}^{n+1}} - \frac{C_{i_2}}{f_{iow}^{n+1}})] \\
& (1-w_{g_s}) \frac{\partial \rho_g}{\partial p_o} \Big|_{i+1,j,k} \sum_i [(T c_{pi} + L_{vi}) D_{ig} \Big|_{i+1,j,k}^{n+1} (\frac{C_{i_2}}{f_{iog}^{n+1}} - \frac{C_{i_2}}{f_{iog}^{n+1}})] \\
& \sum_i [w_{w_s} T \rho_w c_p D_{iw} \Big|_{i,j,k}^{n+1} + (1-w_{w_s}) T \rho_w c_p D_{iw} \Big|_{i+1,j,k}^{n+1} (-\frac{C_{i_2}}{f_{iow}^2} \frac{\partial f_{iow}}{\partial p_o}) \Big|_{i+1,j,k} \\
& \sum_i [w_{g_s} \rho_g (T c_p + L_{vi}) D_{ig} \Big|_{i,j,k}^{n+1} + (1-w_{g_s}) T \rho_g (T c_p + L_{vi}) D_{ig} \Big|_{i+1,j,k}^{n+1} (-\frac{C_{i_2}}{f_{iog}^2} \frac{\partial f_{iog}}{\partial p_o}) \Big|_{i+1,j,k} \} \quad (4.71)
\end{aligned}$$

Derivative of G with respect to S_w

$$\begin{aligned}
\frac{\partial G_{i,j,k}}{\partial S_{wi+1,j,k}} &= \frac{A_x k_x k_{rw} \rho_w}{\mu_w \Delta x} \Big|_{i,j,k} s_{i+1} (-\frac{\partial P_{cow}}{\partial S_w} \Big|_{i+1,j,k}) \\
&\cdot (s_{i+1} T_{i+1,j,k}^{n+1} \sum_i (c_p \frac{C_{i_2}}{f_{iow}} \Big|_{i+1,j,k}^{n+1} + s_i T_{i,j,k}^{n+1} \sum_i (c_p \frac{C_{i_2}}{f_{iow}} \Big|_{i,j,k}^{n+1} + s_{i-1} T_{i-1,j,k}^{n+1} \sum_i (c_p \frac{C_{i_2}}{f_{iow}} \Big|_{i-1,j,k}^{n+1}))
\end{aligned}$$

$$\begin{aligned}
& + T_{i,j,k} \sum_i (c_p, C_{i_o})|_{i,j,k} [(1 - w_{o_s}) \frac{A_x k_x \rho_o}{\mu_o \Delta x} \frac{\partial k_{r_o}}{\partial S_w} |_{i+1,j,k} (p_{o_{i+1},j,k}^{n+1} - p_{o_{i,j,k}}^{n+1} - \rho_{o_{i+1},j,k}^{n+1} g D_{i+1,j,k} + \rho_{o_{i,j,k}}^{n+1} g D_{i,j,k})] \\
& + T_{i,j,k} \sum_i (c_p, \frac{C_{i_o}}{f_{iow}})|_{i,j,k} [(1 - w_{w_s}) \frac{A_x k_x \rho_w}{\mu_w \Delta x} \frac{\partial k_{r_w}}{\partial S_w} |_{i+1,j,k} \\
& \cdot (p_{o_{i+1},j,k}^{n+1} - p_{o_{i,j,k}}^{n+1} - \rho_{w_{i+1},j,k}^{n+1} g D_{i+1,j,k} + \rho_{w_{i,j,k}}^{n+1} D_{i,j,k} - P_{cow_{i+1},j,k} + P_{cow_{i,j,k}}) \\
& - \{ w_{w_s} \frac{A_x k_x k_{rw} \rho_w}{\mu_w \Delta x} |_{i,j,k}^{n+1} + (1 - w_{w_s}) \frac{A_x k_x k_{rw} \rho_w}{\mu_w \Delta x} |_{i+1,j,k}^{n+1} \} \frac{\partial P_{cow}}{\partial S_w} |_{i+1,j,k}] \quad (4.72)
\end{aligned}$$

Derivative of G with respect to S_g

$$\begin{aligned}
\frac{\partial G_{i,j,k}}{\partial S_{g_{i+1},j,k}} & = T_{i,j,k} \sum_i (c_p, C_{i_o})|_{i,j,k} [(1 - w_{o_s}) \frac{A_x k_x \rho_o}{\mu_o \Delta x} \frac{\partial k_{r_o}}{\partial S_g} |_{i+1,j,k} \\
& \cdot (p_{o_{i+1},j,k}^{n+1} - p_{o_{i,j,k}}^{n+1} - \rho_{o_{i+1},j,k}^{n+1} g D_{i+1,j,k} + \rho_{o_{i,j,k}}^{n+1} g D_{i,j,k})] + s_{i+1} \frac{A_x k_x k_{rg} \rho_w}{\mu_g \Delta x} |_{i,j,k} \frac{\partial P_{cgo}}{\partial S_g} |_{i+1,j,k} \\
& \cdot (s_{i+1} \sum_i (c_p, T + L_{vi}) \frac{C_{i_o}}{f_{iog}} |_{i+1,j,k}^{n+1} + s_i \sum_i (c_p, T + L_{vi}) \frac{C_{i_o}}{f_{iog}} |_{i,j,k}^{n+1} + s_{i-1} \sum_i (c_p, T + L_{vi}) \frac{C_{i_o}}{f_{iog}} |_{i-1,j,k}^{n+1} \\
& + \sum_i (c_p, T + L_{vi}) \frac{C_{i_o}}{f_{iog}} |_{i,j,k} [(1 - w_{g_s}) \frac{A_x k_x \rho_g}{\mu_g \Delta x} \frac{\partial k_{r_g}}{\partial S_g} |_{i+1,j,k} \\
& \cdot (p_{o_{i+1},j,k}^{n+1} - p_{o_{i,j,k}}^{n+1} - \rho_{g_{i+1},j,k}^{n+1} g D_{i+1,j,k} + \rho_{g_{i,j,k}}^{n+1} D_{i,j,k} - P_{cgo_{i+1},j,k} - P_{cgo_{i,j,k}}) \\
& + \{ w_{g_s} \frac{A_x k_x k_{rg} \rho_g}{\mu_g \Delta x} |_{i,j,k}^{n+1} + (1 - w_{g_s}) \frac{A_x k_x k_{rg} \rho_g}{\mu_g \Delta x} |_{i+1,j,k}^{n+1} \} \frac{\partial P_{cgo}}{\partial S_g} |_{i+1,j,k}] \quad (4.73)
\end{aligned}$$

Derivative of G with respect to T

$$\begin{aligned}
\frac{\partial G_{i,j,k}}{\partial T_{i+1,j,k}} & = \frac{A_x k_{hx}}{\Delta x} |_{i+1,j,k}^{n+1} + \frac{A_x k_x k_{ro} \rho_w}{\mu_o \Delta x} |_{i,j,k} [(-s_{i+1} g D_{i+1,j,k} \frac{\partial \rho_o}{\partial T}) \\
& \cdot (s_{i+1} T_{i+1,j,k}^{n+1} \sum_i (c_p, C_{i_o})|_{i+1,j,k}^{n+1} + s_i T_{i,j,k}^{n+1} \sum_i (c_p, C_{i_o})|_{i,j,k}^{n+1} + s_{i-1} T_{i-1,j,k}^{n+1} \sum_i (c_p, C_{i_o})|_{i-1,j,k}^{n+1} \\
& + (s_{i+1} p_{o_{i+1},j,k}^{n+1} + s_i p_{o_{i,j,k}}^{n+1} + s_{i-1} p_{o_{i-1},j,k}^{n+1} \\
& - s_{i+1} g D_{i+1,j,k} \rho_{o_{i+1},j,k}^{n+1} - s_i g D_{i,j,k} \rho_{o_{i,j,k}}^{n+1} - s_{i-1} g D_{i-1,j,k} \rho_{o_{i-1},j,k}^{n+1}) \\
& \cdot (s_{i+1} \sum_i c_{pi} C_{i_o} |_{i+1,j,k}) + T_{i,j,k} \sum_i (c_p, C_{i_o})|_{i,j,k} [(1 - w_{o_s}) \{ \frac{A_x k_x}{\Delta x} \frac{\partial}{\partial T} (\frac{k_{ro} \rho_o}{\mu_o}) |_{i+1,j,k} \\
& \cdot (p_{o_{i+1},j,k}^{n+1} - p_{o_{i,j,k}}^{n+1} - \rho_{o_{i+1},j,k}^{n+1} g D_{i+1,j,k} + \rho_{o_{i,j,k}}^{n+1} g D_{i,j,k}) - \frac{A_x k_x k_{ro} \rho_w}{\mu_o \Delta x} |_{i,j,k} g D_{i+1,j,k} \frac{\partial \rho_o}{\partial T} |_{i+1,j,k}] \\
& + \frac{A_x k_x k_{rw} \rho_w}{\mu_w \Delta x} |_{i,j,k} [(s_{i+1} \frac{\partial P_{cow}}{\partial T} |_{i+1,j,k} - s_{i+1} g D_{i+1,j,k} \frac{\partial \rho_w}{\partial T} |_{i+1,j,k}) \\
& \cdot (s_{i+1} T_{i+1,j,k}^{n+1} \sum_i (c_p, \frac{C_{i_o}}{f_{iow}})|_{i+1,j,k}^{n+1} + s_i T_{i,j,k}^{n+1} \sum_i (c_p, \frac{C_{i_o}}{f_{iow}})|_{i,j,k}^{n+1} + s_{i-1} T_{i-1,j,k}^{n+1} \sum_i (c_p, \frac{C_{i_o}}{f_{iow}})|_{i-1,j,k}^{n+1} \\
& + (s_{i+1} p_{o_{i+1},j,k}^{n+1} + s_i p_{o_{i,j,k}}^{n+1} + s_{i-1} p_{o_{i-1},j,k}^{n+1} \\
& - s_{i+1} P_{cow_{i+1},j,k}^{n+1} - s_i P_{cow_{i,j,k}}^{n+1} + s_{i-1} P_{cow_{i-1},j,k}^{n+1})
\end{aligned}$$

$$\begin{aligned}
& -s_{i+1}gD_{i+1,j,k}\rho_{wi+1,j,k}^{n+1} - s_igD_{i,j,k}\rho_{wi,j,k}^{n+1} - s_{i-1}gD_{i-1,j,k}\rho_{wi-1,j,k}^{n+1})(s_{i+1}\sum_i\frac{c_{pi}C_{io}}{f_{iow}}) \\
& + T_{i,j,k}\sum_i(c_p,\frac{C_{io}}{f_{iow}})|_{i,j,k}[(1-w_{w_s})\{\frac{A_xk_x}{\Delta x}\frac{\partial}{\partial T}(\frac{k_{rw}\rho_w}{\mu_w})|_{i+1,j,k} \\
& \cdot (p_{oi+1,j,k}^{n+1} - p_{oi,j,k}^{n+1} - \rho_{wi+1,j,k}gD_{i+1,j,k} + \rho_{wi,j,k}D_{i,j,k} - P_{csw,i+1,j,k} + P_{csw,i,j,k}) \\
& - \frac{A_xk_xk_{rw}\rho_w}{\mu_w\Delta x}|_{i,j,k}(gD_{i+1,j,k}drtw + dpwt))\} \\
& + \frac{A_xk_xk_{rg}\rho_w}{\mu_g\Delta x}|_{i,j,k}[(s_{i+1}\frac{\partial P_{cgo}}{\partial T}|_{i+1,j,k} - s_{i+1}gD_{i+1,j,k}\frac{\partial\rho_g}{\partial T}|_{i+1,j,k}) \\
& \cdot (s_{i+1}\sum_i(c_p,T+L_{vi})\frac{C_{io}}{f_{iog}}|_{i+1,j,k}^{n+1} + s_i\sum_i(c_p,T+L_{vi})\frac{C_{io}}{f_{iog}}|_{i,j,k}^{n+1} + s_{i-1}\sum_i(c_p,T+L_{vi})\frac{C_{io}}{f_{iog}}|_{i-1,j,k}^{n+1}) \\
& + (s_{i+1}p_{oi+1,j,k}^{n+1} + s_ip_{oi,j,k}^{n+1} + s_{i-1}p_{oi-1,j,k}^{n+1} \\
& + s_{i+1}P_{cgo,i+1,j,k}^{n+1} + s_iP_{cgo,i,j,k}^{n+1} + s_{i-1}P_{cgo,i-1,j,k}^{n+1}) \\
& - s_{i+1}gD_{i+1,j,k}\rho_{gi+1,j,k}^{n+1} - s_igD_{i,j,k}\rho_{gi,j,k}^{n+1} - s_{i-1}gD_{i-1,j,k}\rho_{gi-1,j,k}^{n+1})(s_{i+1}\sum_i(c_{pi} + \frac{\partial L_{vi}}{\partial T})\frac{C_{io}}{f_{iog,i+1,j,k}}) \\
& + \sum_i(c_p,T+L_{vi})\frac{C_{io}}{f_{iog}}|_{i,j,k}[(1-w_{g_s})\{\frac{A_xk_x}{\Delta x}\frac{\partial}{\partial T}(\frac{k_{rg}\rho_g}{\mu_g})|_{i+1,j,k} \\
& (p_{oi+1,j,k}^{n+1} - p_{oi,j,k}^{n+1} - \rho_{gi+1,j,k}gD_{i+1,j,k} + \rho_{gi,j,k}D_{i,j,k} - P_{cgo,i+1,j,k} - P_{cgo,i,j,k}) \\
& \cdot (gD_{i+1,j,k}drtg - dpt))\} \\
& + \sum_i\frac{A_x}{\Delta x}|_{i+\frac{1}{2},j,k}^{n+1}[(1-w_{os})D_{io}\{\rho_{oi}c_{pi} + \rho_{oi}T\frac{\partial c_{pi}}{\partial T} + c_{pi}T\frac{\partial\rho_{oi}}{\partial T}|_{i+1,j,k}\}]|_{i+1,j,k}(C_{ioi+1,j,k} - C_{ioi,j,k}) \\
& + \sum_i\frac{A_x}{\Delta x}|_{i+\frac{1}{2},j,k}^{n+1}[(1-w_{ws})D_{iw}\{\rho_{wi}c_{pi} + \rho_{wi}T\frac{\partial c_{pi}}{\partial T} + c_{pi}T\frac{\partial\rho_{wi}}{\partial T}|_{i+1,j,k}\}]|_{i+1,j,k}(\frac{C_{io}}{f_{iow,i+1,j,k}} - \frac{C_{io}}{f_{iow,i,j,k}}) \\
& + \sum_i\frac{A_xD_{iw}\rho_{wi}c_{pi}T}{\Delta x}|_{i+\frac{1}{2},j,k}^{n+1}\cdot(-\frac{C_{io}}{f_{iow}^2}\frac{\partial f_{iow}}{\partial T})_{i+1,j,k} \\
& + \sum_i\frac{A_x}{\Delta x}|_{i+\frac{1}{2},j,k}^{n+1}[(1-w_{gs})D_{ig}\{\rho_{gi}c_{pi} + \rho_{gi}T\frac{\partial c_{pi}}{\partial T} + c_{pi}T\frac{\partial\rho_{gi}}{\partial T}|_{i+1,j,k} + \rho_{gi}\frac{\partial L_{vi}}{\partial T} + L_{vi}\frac{\partial\rho_{gi}}{\partial T}|_{i+1,j,k}\}]|_{i+1,j,k} \\
& \cdot (\frac{C_{io}}{f_{iog,i+1,j,k}} - \frac{C_{io}}{f_{iog,i,j,k}}) + \sum_i\frac{A_xD_{ig}\rho_{gi}(c_{pi}T + L_{vi})}{\Delta x}|_{i+\frac{1}{2},j,k}^{n+1}\cdot(-\frac{C_{io}}{f_{iog}^2}\frac{\partial f_{iog}}{\partial T})_{i+1,j,k} \quad (4.74)
\end{aligned}$$

Derivative of G with respect to C_{io}

$$\begin{aligned}
\frac{\partial G_{i,j,k}}{\partial C_{ioi+1,j,k}} &= \frac{A_xk_xk_{ro}\rho_w}{\mu_o\Delta x}|_{i,j,k}[(s_{i+1}p_{oi+1,j,k}^{n+1} + s_ip_{oi,j,k}^{n+1} + s_{i-1}p_{oi-1,j,k}^{n+1} \\
& - s_{i+1}gD_{i+1,j,k}\rho_{oi+1,j,k}^{n+1} - s_igD_{i,j,k}\rho_{oi,j,k}^{n+1} - s_{i-1}gD_{i-1,j,k}\rho_{oi-1,j,k}^{n+1}) \cdot s_{i+1}T_{i+1,j,k}\sum_i(c_p,C_{io})|_{i+1,j,k} \\
& - (s_{i+1}T_{i+1,j,k}\sum_i(c_p,C_{io})|_{i+1,j,k}^{n+1} + s_iT_{i,j,k}^{n+1}\sum_i(c_p,C_{io})|_{i,j,k}^{n+1} + s_{i-1}T_{i-1,j,k}^{n+1}\sum_i(c_p,C_{io})|_{i-1,j,k}^{n+1}) \\
& (s_{i+1}gD_{i+1,j,k}\frac{\partial\rho_o}{\partial C_{io}}|_{i+1,j,k})] \\
& + T_{i,j,k}\sum_i(c_p,C_{io})|_{i,j,k}[(1-w_{os})\frac{A_xk_xk_{ro}}{\Delta x}\frac{\partial\rho_o}{\partial C_{io}}|_{i+1,j,k}(p_{oi+1,j,k}^{n+1} - p_{oi,j,k}^{n+1} - \rho_{oi+1,j,k}gD_{i+1,j,k} + \rho_{oi,j,k}gD_{i,j,k})]
\end{aligned}$$

$$\begin{aligned}
& + \frac{A_x k_x k_{rw} \rho_w}{\mu_w \Delta x} \Big|_{i,j,k} [(s_{i+1} p_{oi+1,j,k}^{n+1} + s_i p_{oi,j,k}^{n+1} + s_{i-1} p_{oi-1,j,k}^{n+1} \\
& - s_{i+1} p_{cowi+1,j,k}^{n+1} - s_i p_{cowi,j,k}^{n+1} + s_{i-1} p_{cowi-1,j,k}^{n+1} \\
& - s_{i+1} g D_{i+1,j,k} \rho_{wi+1,j,k}^{n+1} - s_i g D_{i,j,k} \rho_{wi,j,k}^{n+1} - s_{i-1} g D_{i-1,j,k} \rho_{wi-1,j,k}^{n+1}) (s_{i+1} T_{i+1,j,k} c_{pi} / f_{iow} \Big|_{i+1,j,k} \\
& - (s_{i+1} T_{i+1,j,k}^{n+1} \sum_i (c_p, \frac{C_{i_2}}{f_{iow}}) \Big|_{i+1,j,k}^{n+1} + s_i T_{i,j,k}^{n+1} \sum_i (c_p, \frac{C_{i_2}}{f_{iow}}) \Big|_{i,j,k}^{n+1} + s_{i-1} T_{i-1,j,k}^{n+1} \sum_i (c_p, \frac{C_{i_2}}{f_{iow}}) \Big|_{i-1,j,k}^{n+1}) \\
& \cdot (s_{i+1} g D_{i+1,j,k} \frac{\partial \rho_w}{\partial C_{i_2}} \Big|_{i+1,j,k})] + T_{i,j,k} \sum_i (c_p, \frac{C_{i_2}}{f_{iow}}) \Big|_{i,j,k} \\
& \cdot [(1 - w_{ws}) \frac{A_x k_x k_{rw}}{\Delta x} \frac{\partial \rho_w}{\partial C_{i_2}} \Big|_{i+1,j,k} (p_{oi+1,j,k}^{n+1} - p_{oi,j,k}^{n+1} - \rho_{wi+1,j,k} g D_{i+1,j,k} + \rho_{wi,j,k} D_{i,j,k} - P_{cowi+1,j,k} + P_{cowi,j,k}) \\
& + \frac{A_x k_x k_{rg} \rho_w}{\mu_g \Delta x} \Big|_{i,j,k} [(s_{i+1} p_{oi+1,j,k}^{n+1} + s_i p_{oi,j,k}^{n+1} + s_{i-1} p_{oi-1,j,k}^{n+1} \\
& + s_{i+1} p_{cgoi+1,j,k}^{n+1} + s_i p_{cgoi,j,k}^{n+1} + s_{i-1} p_{cgoi-1,j,k}^{n+1} \\
& - s_{i+1} g D_{i+1,j,k} \rho_{gi+1,j,k}^{n+1} - s_i g D_{i,j,k} \rho_{gi,j,k}^{n+1} - s_{i-1} g D_{i-1,j,k} \rho_{gi-1,j,k}^{n+1}) (s_{i+1} (T_{i+1,j,k} c_{pi} + L_{vi}) / f_{iog} \\
& - (s_{i+1} \sum_i (c_p, T + L_{vi}) \frac{C_{i_2}}{f_{iog}} \Big|_{i+1,j,k}^{n+1} + s_i \sum_i (c_p, T + L_{vi}) \frac{C_{i_2}}{f_{iog}} \Big|_{i,j,k}^{n+1} + s_{i-1} \sum_i (c_p, T + L_{vi}) \frac{C_{i_2}}{f_{iog}} \Big|_{i-1,j,k}^{n+1}) \\
& \cdot (s_{i+1} g D_{i+1,j,k} \frac{\partial \rho_g}{\partial C_{i_2}} \Big|_{i+1,j,k})] + \sum_i (c_p, T + L_{vi}) \frac{C_{i_2}}{f_{iog}} \Big|_{i,j,k} [(1 - w_{gs}) \frac{A_x k_x k_{rg}}{\Delta x} \frac{\partial \rho_g}{\partial C_{i_2}} \Big|_{i+1,j,k} \\
& \cdot (p_{oi+1,j,k}^{n+1} - p_{oi,j,k}^{n+1} - \rho_{gi+1,j,k} g D_{i+1,j,k} + \rho_{gi,j,k} D_{i,j,k} - P_{cgoi+1,j,k} - P_{cgoi,j,k}) \\
& + \frac{A_x}{\Delta x} \Big|_{i+\frac{1}{2},j,k}^{n+1} (1 - w_{os}) D_{ioi+1,j,k} c_{pi+1,j,k} T_{i+1,j,k} \frac{1}{f_{iow i+1,j,k}} (\rho_{oi+1,j,k} + C_{ioi+1,j,k} \frac{\partial \rho_o}{\partial C_{i_2}} \Big|_{i+1,j,k}) \\
& + \frac{A_x}{\Delta x} \Big|_{i+\frac{1}{2},j,k}^{n+1} (1 - w_{ws}) D_{iwi+1,j,k} c_{pi+1,j,k} T_{i+1,j,k} \frac{1}{f_{iow i+1,j,k}} (\rho_{wi+1,j,k} + C_{ioi+1,j,k} \frac{\partial \rho_w}{\partial C_{i_2}} \Big|_{i+1,j,k}) \\
& + \frac{A_x}{\Delta x} \Big|_{i+\frac{1}{2},j,k}^{n+1} (1 - w_{gs}) D_{igi+1,j,k} c_{pi+1,j,k} T_{i+1,j,k} \frac{1}{f_{iog i+1,j,k}} (\rho_{gi+1,j,k} + C_{ioi+1,j,k} \frac{\partial \rho_g}{\partial C_{i_2}} \Big|_{i+1,j,k}) \quad (4.75)
\end{aligned}$$

Numerical Derivatives

The numerical derivatives of the F_i and G functions were calculated using the following type of equation, giving $\frac{\partial F_i}{\partial p_o}$ at block i, j, k , for example:

$$\frac{\partial F_i}{\partial p_o} \Big|_{i,j,k} = \frac{F_i(p_{oi,j,k} + \epsilon, \bar{x}) - F_i(p_{oi,j,k}, \bar{x})}{\epsilon} \quad (4.76)$$

where $\bar{x}$ represents all other variables, the values of which are held constant at the current iteration.

Source-Sink Terms

The source-sink terms consist of injection/production terms for oleic, aqueous, and vapour phases as well as for enthalpy. The procedure used for injection and production wells is described below. The terms are taken to be fully implicit in all cases.

Injection Well

An injection well is treated rather simply. In this case, the injection rate of a component, or a phase with a given composition, is specified. For example, the injection rate of the aqueous phase q_w^* , sm^3/s , may be given with 100% water. This can be converted into an appropriate source term m_i^* , $\text{kg}/\text{s-m}^3$, in a straightforward manner. The enthalpy term follows directly from this term, given the injected enthalpy per unit mass.

Two components, if injected simultaneously, can be treated in the same manner, although it is numerically more convenient to consider alternating injection, as would be the case in the actual field practice.

It should be noted that only Abou-Kassem (1981) has rigorously treated wet steam injection as a two-phase injection problem. Earlier, Ito (1976) employed an approximate approach of this type. The result was pressure oscillation at the injection well, which can lead to solution convergence problems.

Production Well

The case of a production well is more complex than that of an injection well. The present simulator allows for three options: (i) the oil production rate is specified, (ii) the total liquid production rate is specified (e.g. pump capacity), or (iii) the well bottomhole flowing pressure is specified. In each case, the phase production rates are obtained from the basic mobility relationship, as shown below.

If the oil, water, and vapour production rates are q_o^* , q_w^* , q_g^* , then the following relationships hold:

$$\frac{\rho_{osc} q_o^*}{\rho_{wsc} q_w^*} = \frac{\frac{-k_{ro} \rho_o}{\mu_o} \frac{\partial \Phi_o}{\partial r}}{\frac{-k_{rw} \rho_w}{\mu_w} \frac{\partial \Phi_w}{\partial r}} \quad (4.77)$$

and

$$\frac{\rho_{osc} q_o^*}{\rho_{gsc} q_{gsc,raa}^*} = \frac{\frac{-k_{ro} \rho_o}{\mu_o} \frac{\partial \Phi_o}{\partial r}}{\frac{-k_{rg} \rho_g}{\mu_g} \frac{\partial \Phi_g}{\partial r}} \quad (4.78)$$

Thus, q_w^* and q_g^* can be obtained from:

$$q_g^* = \left(\frac{k_{rg} \rho_g \rho_{osc} \mu_o}{k_{ro} \rho_o \rho_{gsc} \mu_g} \frac{\partial \Phi_g}{\partial r} \right) q_o^* \quad (4.79)$$

or, $q_g^* = g \cdot q_o^*$, where g is the above multiplier.

Similarly,

$$q_w^* = \left(\frac{k_{rw} \rho_w \rho_{osc} \mu_o}{k_{ro} \rho_o \rho_{wsc} \mu_w} \frac{\partial \Phi_w}{\partial r} \right) q_o^* = f \cdot q_o^* \quad (4.80)$$

If the total liquid production rate q_t^* is given, it can be broken into oil and water phase production rates, as follows:

$$q_w^* = \frac{f q_t^*}{1 + f} \quad (4.81)$$

and

$$q_o^* = \frac{q_w^*}{f} \quad (4.82)$$

The total liquid rate is useful for a pumping well, where q_t^* is less than or equal to the pump capacity. If, on the other hand, the bottomhole flowing pressure p_{wf} is given, the oil production rate is given by (based upon steady state radial flow in terms of average pressure):

$$q_o^* = \frac{2\pi h k k_{ro} (\Phi_b - \Phi_{wf}) \rho_o}{\mu_o [\ln \frac{r_e}{r_w} - \frac{1}{2} + s] \rho_{osc}}, \quad (4.83)$$

where Φ_b is the well block pressure, and r_e is the drainage radius equivalent to the block area. If the well is producing against a fluid head in the wellbore, the above equation can be used.

Once the phase production rates are calculated, the individual component production rates are obtained from phase compositions, which are known at the well block.

The heat production rates are obtained directly from the enthalpy of the produced components and the phase production rates. Such a term is given below:

$$\rho_{osc}q_o \cdot \sum_i C_{o,c_p,T} + \rho_{wsc}q_w \cdot \sum_i C_{w,c_p,T} + \rho_{gsc}q_{gs} \cdot \sum_i C_{g,(c_p,T+L_v)} \quad (4.84)$$

Three-Phase Relative Permeabilities

Determination of three-phase relative permeabilities by laboratory experiments is difficult and time consuming, although both steady and unsteady state methods have been used successfully for obtaining such data. In reservoir simulation, the unsteady state method is used more commonly because of its relative simplicity [Johnson, Bossler, and Nauman (1959)]. This method is based upon the Buckley-Leverett theory, and thus assumes an infinite saturation at the front. Because of this, the results should be used with caution, especially if viscous instabilities are present. Islam and Bentsen (1987) have discussed this question in a number of publications.

Two-phase relative permeabilities used in simulations are usually experimentally obtained. Three-phase values are often synthesized from experimental oil-water and oil-gas relations, employing Stone's method (1970,1973), or one of its variations. We shall briefly discuss Stone's method, and the Naar-Wygal-Henderson (1961,1962) method, as well as a modification of the latter, which was developed for this study.

Stone's Method

The following assumptions are made in developing Stone's method [Stone(1973)]:

1. The water relative permeability is a function of water saturation only, and does not depend on the relative proportions of oil and gas phases. Thus,

$$k_{rw} = k_{rw}(S_w). \quad (4.85)$$

2. The gas relative permeability is a function of gas saturation only, and does not depend on the relative proportions of oil and water phases. Thus,

$$k_{rg} = k_{rg}(S_g). \quad (4.86)$$

3. The oil relative permeability is a function of both water and gas saturations, i.e.

$$k_{ro} = k_{ro}(S_w, S_g). \quad (4.87)$$

Keeping these rules in mind, k_{rw} and k_{rg} can be obtained simply from two-phase oil-water and oil-gas relative permeability data, while k_{ro} is obtained from the following relationship. This is a modified form of Stone's original equation.

$$k_{ro} = k_{row}^* \left[\left(\frac{k_{row}}{k_{row}^*} + k_{rw} \right) \left(\frac{k_{rog}}{k_{row}^*} + k_{rg} \right) - (k_{row} + k_{rog}) \right], \quad (4.88)$$

where k_{row} and k_{rog} are, respectively, the relative permeabilities to oil in the water-oil and gas-oil systems, and are obtained from two-phase relative permeability curves, and

$$k_{row}^* = k_{row}(S_{wr}). \quad (4.89)$$

Shutler (1969) suggested an equation that relates the actual three-phase oil saturation S_o to a two-phase oil saturation S_2 in a gas-oil system, where

$$S_2 = \frac{(1 - S_w - S_g)(1 - S_{wr})}{1 - S_w}. \quad (4.90)$$

Then the relative permeability to oil in the three-phase system is given by:

$$k_{ro} = \frac{k_{row}(S_w)k_{rog}(S_2)}{k_{row}(S_{wr})}, \quad (4.91)$$

where

k_{row} = relative permeability to oil in a water-oil system

k_{rog} = relative permeability to oil in a oil-gas-irreducible water system

Naar-Wygal-Henderson Method

Naar, Wygal and Henderson (1961) proposed the following relationships for three-phase relative permeabilities, based upon simplification of their integral equations:

$$k_{rw} = \left[\frac{S_w - S_{wr}}{1 - S_{wr}} \right]^4, \quad (4.92)$$

$$k_{ro} = S_o^3 \frac{(1 - S_g + S_w - 2S_{wr})}{(1 - S_{wr})^4}, \quad (4.93)$$

$$k_{rg} = S_g^3 \frac{(2 - S_g - 2S_{wr})}{(1 - S_{wr})^4} \quad (4.94)$$

The above equations are used widely in reservoir simulation. These equations are simplifications of more complex forms. It is seen that only a single parameter S_w is required, which often becomes a history matching parameter. Aktan and Farouq Ali (1972) showed that the Naar-Wygal-Henderson equations gave relative permeabilities close to those obtained from Stone's method. Considering the uncertainties in experimental measurements of relative permeabilities, these equations offer a useful alternative.

The above equations give $k_{rw} = 0$ when $S_w = S_{wr}$. However, they do not properly describe the behaviour of k_{ro} and k_{rg} at the critical oil and gas saturations. These effects must be considered in simulation. Most investigators simply make k_{ro} zero, when $S_o \leq S_{or}$ and k_{rg} zero, when $S_g \leq S_{gc}$. This is not satisfactory in solution techniques involving derivatives of relative permeability, as in the fully implicit procedure used in the present work, or in the semi-implicit techniques. In semi- or fully implicit methods, nonlinearities near the critical points are severe, and smooth functions need to be used.

Modified Relative Permeability Equations

A modification of the three-phase relative permeability equations (4.92) to (4.94) is suggested, in order to properly account for the behaviour of the relative permeabilities to oil and gas at their critical saturation values. This modification does not allow for the mobility of oil and gas phases at or below the critical values, and it provides a smooth transition of relative permeability from zero to nonzero values. The proposed modifications are as follows.

Relative permeability to oil:

In Eq.(4.93), the term S_o^3 can be replaced by $C_1(S_o - S_{or})S_o^2$. As a result, the modified relative permeability to oil k_{roM} is given by

$$k_{roM} = C_1(S_o - S_{or})S_o^2 \frac{(1 - S_g + S_w - 2S_{wr})}{(1 - S_{wr})^4} \quad (4.95)$$

and

$$k_{roM} = 0 \quad \text{if} \quad S_o < S_{or}, \quad (4.96)$$

where C_1 is a constant that is obtained as follows. Equation (4.95) has to be consistent with Eq.(4.93), when $S_g = 0$ and $S_w = S_{wr}$, where S_{wr} is irreducible water saturation. Therefore, we can equate them and solve for C_1 . In Eq.(4.93), if $S_g = 0$ and $S_w = S_{wr}$, then $k_{ro} = 1$. In Eq.(4.95):

$$1 = k_{roM} = C_1(S_o - S_{or})S_o^2 \frac{(1 - S_{wr})}{(1 - S_{wr})^4}, \quad (4.97)$$

but when $S_g = 0$ and $S_w = S_{wr}$, $S_o = 1 - S_{wr}$, giving

$$C_1 = \frac{1 - S_{wr}}{1 - S_{wr} - S_{or}}. \quad (4.98)$$

Therefore:

$$k_{roM} = \frac{1 - S_{wr}}{1 - S_{wr} - S_{or}}(S_o - S_{or})S_o^2 \frac{(1 - S_g + S_w - 2S_{wr})}{(1 - S_{wr})^4}. \quad (4.99)$$

Notice that the subscript M stands for the modified form.

Relative Permeability to Gas:

In this case, the term S_g^3 in Eq.(4.94) can be replaced by $C_2(S_g - S_{gc})S_g^2$, so that the modified equation is written as:

$$k_{rgM} = C_2(S_g - S_{gc})S_g^2 \frac{(2 - S_g - 2S_{wr})}{(1 - S_{wr})^4}, \quad (4.100)$$

Again, in this case, in order to keep Eq.(4.100) consistent with Eq.(4.94), when $S_o = 0$ and $S_w = S_{wr}$, the two expressions are considered to be equal; therefore, C_2 is obtained as follows. In Eq.(4.94), $k_{rg} = 1$, thus

$$C_2 = \frac{1 - S_{wr}}{1 - S_{wr} - S_{gc}}, \quad (4.101)$$

and

$$k_{rgM} = \frac{1 - S_{wr}}{1 - S_{wr} - S_{gc}}(S_g - S_{gc})S_g^2 \frac{(2 - S_g - 2S_{wr})}{(1 - S_{wr})^4}, \quad (4.102)$$

and

$$k_{rgM} = 0 \quad \text{if} \quad S_g < S_{gc}. \quad (4.103)$$

In this manner, the known values of S_{or} and S_{gc} can be incorporated into the original Naar-Wygal-Henderson equations. The form of Eqs.(4.99) and (4.102) is suitable when account has to be taken of temperature dependence of relative permeabilities. In such a case, the residual oil and irreducible water saturations may be taken to be functions of temperature [Diaz (1974), Ferrer (1975), Weinbrandt and Ramey (1975)].

Figures 4.1 and 4.2 show a comparison of the Naar-Wygal-Henderson and the modified relative permeabilities. The plots show

$$\frac{k_{roNH} - k_{roM}}{k_{roNH}} = \frac{S_{or}(1 - S_g - S_{or})}{S_g(1 - S_{or} - S_{or})}$$

versus S_g in Fig. 4.1, and

$$\frac{k_{rgNH} - k_{rgM}}{k_{rgNH}} = \frac{S_{gc}(1 - S_g - S_{or})}{S_g(1 - S_{gc} - S_{or})}$$

versus S_g in Fig. 4.2. It is seen that for high values of S_o and S_g the difference between the Naar-Wygal-Henderson and modified permeabilities is small.

Temperature Dependence of Relative Permeabilities

Several investigators have studied the effect of temperature on relative permeabilities [Poston et al (1970), Weinbrandt and Ramey (1972), Sufi and Brigham (1984), and Polikar et al. (1986)], and have reported conflicting experimental data. The question whether relative permeabilities are temperature dependent is open to controversy. It seems that in clean sand, with no clays present, relative permeabilities are essentially independent of temperature. On the other hand, in naturally occurring sands, with considerable amounts of clay minerals, relative permeabilities are temperature dependent, possibly due to rock-fluid interactions and other effects, such as thermal expansion and grain dislocations. In this work, we will not be concerned with this question. The simulations conducted considered both temperature dependent and temperature invariant relative permeabilities. A few investigators have studied this effect on steam processes [Ferrer(1975)]. It was observed that oil recovery increased for the temperature dependent relative permeabilities. Oil recovery was found to increase more noticeably in the case of steam drive than for cyclic steam stimulation. This occurs because production of hot fluids causes temperature reduction and consequently acceleration of pressure depletion in cyclic steaming. Diaz (1974) reported similar results for the simulation of cyclic hot water stimulation. In his studies, however, the effect of temperature dependence of relative permeabilities on oil recovery and production rate were less significant than in the case of steam. This could be explained by

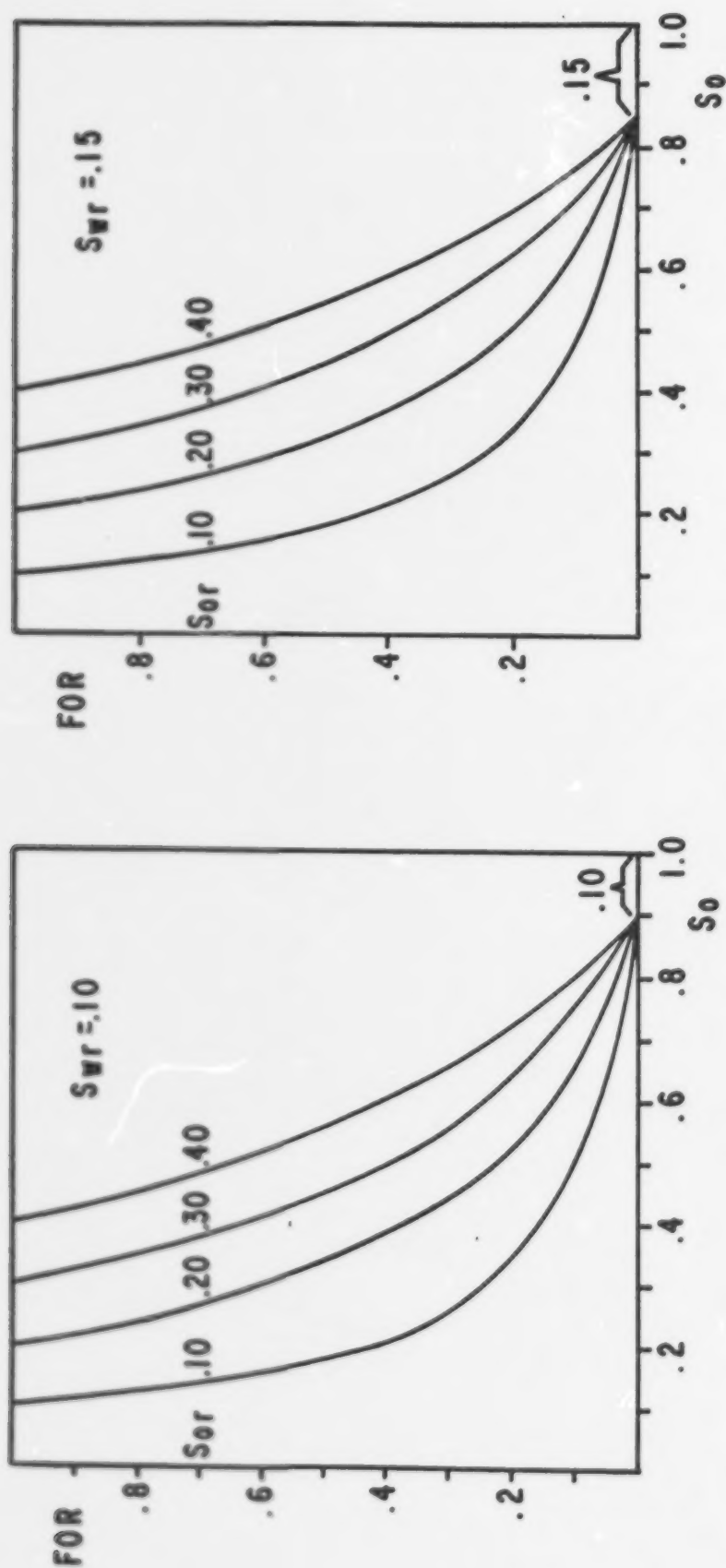


Figure 4.1 Comparison of the Naar-Wygal-Henderson and Modified Oil Relative Permeability values, $FOR = (k_{rNH-kroM})/k_{roM}$

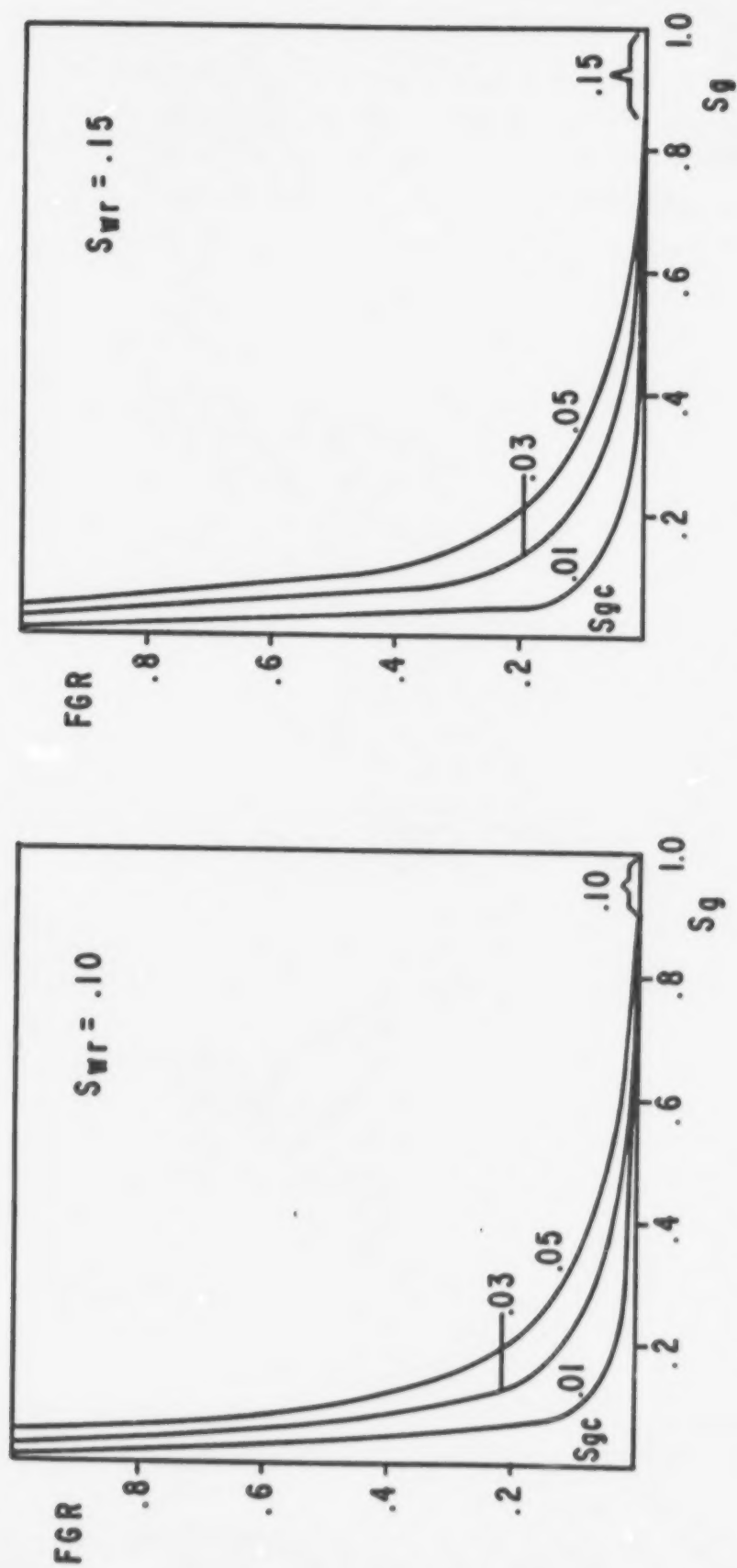


Figure 4.2 Comparison of the Naar-Wygal-Henderson and Modified Gas Relative Permeability Values, $FOR = (k_{rNH} - k_{rM}) / k_{rM}$

the lower temperature in the case of hot water injection than for steam soak. Coats and co-workers (1974) reported that difficulties were encountered in matching experimental data when the effect of temperature on relative permeabilities was not taken into account. On the other hand, Shutler (1969,1970) and Weinstein (1974) reported good agreement between calculated and experimental data without considering this effect.

It should be noted that the inclusion of temperature dependence of relative permeabilities provides one more adjustment parameter for obtaining a history match, whether such temperature dependence is real or not.

In the present study, the end-points S_{wr} and S_{or} were made linear functions of temperature, when temperature dependence was to be considered. This agrees with the experimental data of Weinbrandt and Ramey (1972), and is a convenient though not rigorous means of including the effect of temperature on relative permeabilities :

$$S_{or} = a_0 - a_1 T, \quad (4.104)$$

$$S_{wr} = b_0 + b_1 T, \quad (4.105)$$

$$S_{gc} = \text{const.} \quad (4.106)$$

Thermal Upgrading of Heavy Oils

A heavy crude oil, when subjected to mild thermal cracking conditions, exhibits a permanent and considerable reduction in its viscosity and specific gravity. All crudes are susceptible to cracking, however, high temperatures and long times are required to crack heavy crudes, such as the Athabasca bitumen. By subjecting both the original crude and the heat-treated oil to distillation under identical conditions, the amount of upgrading or conversion of crude constituents can be estimated.

Some laboratory tests have been conducted on a variety of crude oils, in order to study the time-temperature history, and to obtain specific degrees of viscosity reduction for each sample. Therefore, it is possible to determine the feasibility of applying heat in the reservoir to facilitate the production of heavy oil, or of utilizing heat to make the surface handling of the oil already produced easier.

At 500 F, the permanent upgrading of physical properties takes place rather slowly. Use of temperatures lower than that will only improve the oil fluidity, which is the case of heated pipelines as currently practiced.

On the other hand, at temperatures above 700 F, coking may take place, which will cause severe operating problems.

Crude oils having low API gravities and high viscosities and pour points cause production difficulties both in and out of the reservoir. In order to avoid surface handling problems, light oils and LPG are blended with heavy crudes to facilitate their handling in pipelines and storage facilities. An alternative technique is to apply thermal cracking. This technique, which is associated with lowering of pour point and viscosity, was employed in the U.S.S.R. many years ago. Egloff and Morrell (1926) suggested severe cracking of a high pour point oil at the wellhead. This would eliminate the need for pipeline heaters as well as diluents. Underground thermal processes may subject large volumes of reservoir crude to a temperature, which is high enough to cause mild thermal cracking. The permanent change in the physical properties of heavy oil as a result of mild thermal cracking was observed by Ball (1941) on oil from the Athabasca oil sands.

Mild thermal cracking or visbreaking is a suggested process in oil recovery to make the oils more pumpable. Mild decomposition, minimum coke formation and the retention of the cracked part in the original crude are characteristics of visbreaking. The oil which has been subjected to the visbreaking process will have lower viscosity, pour point, and specific gravity than the original sample. Therefore, the visbroken crude is upgraded in its physical properties as far as the fluidity is concerned.

In a survey by Henderson and Weber (1965), mild thermal cracking experiments carried out on samples of seven different crude oils have been reported. Six of these samples were chosen from conventional oil reservoirs and one was from the Athabasca oil sands. In their study, Henderson and Weber were concerned about (i) the time that a particular crude could be heated at different temperatures; (ii) establishing a relationship between changes in the crude and the period of heating; and (iii) the important variables of the process. These are discussed in the next section.

Kinetics of the Cracking Process

In a thermal cracking process large molecules of hydrocarbons are decomposed by thermal energy into smaller molecules. Under normal conditions, some small molecules form, which are relatively stable gases or liquids. Also, some unstable or reactive molecules are produced that can polymerize with one another and yield larger molecules than those in the original crude. Provided the pyrolysis is continued for sufficient time, or the temperature is further increased, the original crude will be almost entirely converted into a mixture of light gases (e.g. methane and hydrogen), which are stable, and a solid material, which is coke.

Henderson and Weber (1965) give the following kinetic equation to describe the cracking reaction of pure hydrocarbons as well as petroleum:

$$\ln\left(\frac{C_0}{C}\right) = kt. \quad (4.107)$$

This is the integrated form of the first order rate equation, where

C_0 = percent of reactant initially present, weight fraction,

C = percent of reactant remaining at time t ,

t = time, seconds,

k = specific rate or velocity constant, sec^{-1} .

The specific rate k is given by the integrated Arrhenius equation

$$k = Ae^{-\frac{E}{RT}}, \quad (4.108)$$

where

A = pre-exponent, sec^{-1} ,

E = activation energy, Btu/lb-mole,

T = absolute temperature, R,

R = gas constant = 1.987 Btu/lb-mole-R.

Representation of Upgrading in the Mathematical Model

For the purpose of this study, the upgrading process was represented via an oil viscosity equation, where the viscosity is a function of the fraction upgraded, as follows:

$$\ln \mu = a + b(1 - e^{-At e^{-\frac{E}{RT}}}), \quad (4.109)$$

where μ is the viscosity at 150 F in cp, T is in R, and t is in seconds. The constants a and b were taken from Henderson and Weber's experimental data, for three of the oils tested by them. These are listed in Table 4.1.

Table 4.1

KINETICS CONSTANTS USED FOR UPGRADING

Crude Oil	Log ₁₀ A	Activation Energy, E, kcal/mole	b	a
C	12.13	49.0	-10.067	6.7852
E	9.86	43.6	-6.299	4.2896
Athabasca Bitumen	11.53	49.	-11.16	7.253

Flow of Foams in Porous Media

Rheology of Foam: Foams are complex two-phase, multicomponent fluid systems, with rather unusual flow behaviour in a porous medium. A foam is basically a gas-liquid dispersion that is formed by mixing a gas, such as air or nitrogen, and a liquid to which a surface active agent has been added. A number of previous studies have been devoted to foam rheology in a variety of flow systems, such as laboratory containers, capillary tubes, and porous media (e.g. Bernard (1964), Holm (1968), Raza (1970), and Mast (1972)). Recently, Irani and Solomon (1986) discussed the mechanics of CO₂-foam propagation in a slim tube, and foam stability. A brief description of some of the dominant characteristics of foam are given below. A few studies have also dealt with "oil foams", i.e. dispersions of oil, containing a surface active agent and a gas. Such foams are usually unstable, and even more so at high temperatures. This study will not consider foams of this type.

Fried (1961) conducted the first comprehensive study on the flow of foams in a porous medium. Although this work was done over 25 years ago, it is still useful for reasons of its thoroughness. He reported that an externally generated foam flowed through a porous medium with a resistance considerably greater than that of the gas used for the foam. He also showed that an increase in the surface active agent increased the flow resistance.

Consider first, certain rheological features of a foam. Foam can be generated by injecting gas into a porous medium that initially contains a foaming solution. Raza's (1967, 1970) experimental result showed that anionic foaming agents produce low quality, stable foams, while nonionic agents yield high quality, unstable foams. (Foam quality is defined as the ratio of gas volume to the total foam volume.) Flow tests in a porous medium showed that the foam quality increased as the surfactant concentration increased until a concentration of 0.1% by weight was reached, after which the quality became constant. The time for foam breakthrough was very small up to a surfactant concentration

of 0.1%. Thereafter, the breakthrough time increased 20-fold, reaching a maximum at a concentration of 1% to 8%, and then decreasing somewhat. Chiang (1980) has reported that stable foams formed at 0.6% concentration.

Minssieux (1974) proposed two mechanisms for foam instability, which is strongly influenced by quality. When drainage of liquid and rupture of fluid is the dominant mechanism, foam stability increases with increasing quality. If gas diffusion between adjacent bubbles is the main cause of instability, foam stability will be expected to decrease with increasing quality. The latter effect was dominant in the case of a viscous liquid phase. Possibly, in the flow of an aqueous foam, liquid drainage is the dominant mechanism deciding foam stability. Regarding the effect of temperature and pressure on foam stability, it appears that generally foam stability increases with increasing pressure, and decreases with increasing temperature. The quality decreases with an increase in pressure and/or decrease in temperature, for a given surfactant condition. These results are based upon Wang's (1984) and Maini and Ma's (1984) work.

The mobility reduction factor of foams increases with increasing foam stability due to the similarity in the surface forces affecting the foam properties inside and outside the porous medium. The apparent viscosity of foam depends on a number of factors, including velocity or shear rate, pressure, and temperature. An increase in pressure causes a decrease in the foam quality, and an increase in density. The apparent viscosity of foam is often expressed as a function of foam density, with the viscosity passing through a maximum as the density increases (Grove et al.(1951)). It has been shown by Marsden and Khan (1966) that the apparent viscosity decreases with increasing shear rate and increases with increasing quality. Shear stress versus shear rate plots for foams tend to show that foams have pseudoplastic behaviour. Flow experiments in capillary tubes have shown that the apparent viscosity also depends on the tube radius (Raza and Marsden (1967)). Correcting for slippage and compressibility, it was found that the foam viscosity became independent of quality, but continued to be a function of tube diameter. The

apparent viscosity of a foam would tend to decrease with temperature, other conditions being constant.

Hirasaki and Lawson (1983) proposed a mathematical equation for the apparent viscosity of foam. The viscosity was attributed to: (i) the liquid slugs, (ii) resistance to deformation of the interface of a bubble passing through a capillary and (iii) surface tension gradient. The equation consists of two parameters, which must be determined from experimental data. Effect of temperature was not considered in this work.

Flow in Porous Media: The early work of Fried (1961), and later Bernard (1964) showed that the mobility of foam in a porous medium is lower than that of gas or the liquid constituting the foam. The latter study also showed that the displacement efficiency of a foam was higher in sand packs containing water only as compared to sand packs containing oil only. When both oil and water were present, the performance was somewhere in between. Further studies have shown (Bernard (1964)) that the relative permeability to water as a function of water saturation is not altered in the presence of foam, however, that of the gas is lowered, because the effect of foam is to create a higher trapped gas saturation, which indirectly lowers the relative permeability to water. The presence of oil tends to lower the trapped gas saturation.

There is some difference of opinion on the mechanics of flow of a foam in a porous medium. Marsden and Khan (1966) suggested that the foam components flow simultaneously in a porous medium. Thus, foam mobility was found to decrease with increasing quality. On the other hand, Bernard et al. (1964) proposed that water flows as a continuous phase, while the gas is a discontinuous phase. Still another mechanistic picture was described by Holm (1968), who observed in visual studies that the gas and liquid phases flowed separately in a porous medium by the breaking and reforming of the bubbles. Foam generation and quality have been related to absolute permeability (Raza (1970)). Foam is generated in the longer pores, wherein the foam would tend to flow,

with temporary blockage in the smaller pores. In this manner, it is possible to describe the flow of a foam in a porous medium in at least two different ways: as a single body, or as two separate phases. In any case, the flow behaviour is non-Newtonian.

Application of Foam in Steam Injection

A foam is used in steam injection for two purposes, which are not quite distinct. First, injected with steam it can help control steam mobility, because steam will act as a viscous fluid leading to higher displacement efficiency of the mobilized oil. Secondly, foam can also act as a blocking agent, where gravity override of steam has created a high conductivity path in the upper part of the formation. Steam mobility control by use of foam is likely to be more effective in steamflooding lighter oils, where the steam front is close to vertical. When steam override is present, use of foam as a blocking agent is likely to be more effective. In both cases, formation and flow of foam leads to a large reduction in gas phase mobility.

Elson et al. (1978) have reviewed the literature on the use of foam with steam, concluding that foam is best suited as a blocking agent. Chiang et al. (1980) carried out ambient temperature experiments using a surfactant and water, with nitrogen as gas. They reported that *in situ* formation of foam increased liquid recovery and reduced gravity override. Isaacs et al. (1985) reported steam-foam experiments, showing that steam-foams were formed in the case of one of the surfactants, as indicated by the large pressure drop, when steam was injected. On the other hand, no foam was formed in the case of the other surfactant. They reported that the gas phase relative permeability curves had to be shifted depending on gas velocity and surfactant concentration in order to simulate foam flow.

Representation of Foam in the Mathematical Model

In the present mathematical model, foam was considered to have two effects on steam flow: it increases the apparent viscosity of the steam phase, and it reduces the relative permeability to gas. In the existing literature, there are no consistent data describing foam rheology as a function of surfactant concentration, quality, temperature, and pressure. The same is true for the relative permeability to gas in the presence of a foam. The purpose of this work was to put together the available data in a form in which the dominant aspects of foam flow are represented. The input consisted of the surfactant concentration in the steam zone. This was used to calculate the foam quality. The quality was modified for pressure and temperature effects. Finally, the computed quality was used in the viscosity equation, to calculate the apparent viscosity of foam. In a similar way, the relative permeability to gas was based upon the flow velocity, assuming the presence of a foam after Isaacs et al. (1985). The equations used are as follows, and are based upon the experimental data of Wang (1984), Grove (1951), Marsden and Khan (1966), and Best et al. (1985).

$$x = 1.14205 (0.7975 - 0.90763 C_s)(0.36 + 3.2 \times 10^{-4} p) \exp (-0.001594 T), \quad (4.110)$$

(75 ≤ T ≤ 140°F, 1500 ≤ p ≤ 2000 psia, 0.1 ≤ C_s ≤ 0.33% by wt)

where x is foam quality, fraction, C_s is concentration in steam, fraction, p is pressure in psia, and T is temperature in °F. The apparent viscosity of foam is given by

$$\mu_{app} = -386 + 783 x - 0.4211 \dot{\gamma}, \quad (0.7 \leq x \leq 0.95, 100 \leq \dot{\gamma} \leq 300 \text{ min}^{-1}) \quad (4.111)$$

where $\dot{\gamma}$ is the shear rate, related to velocity v in a porous medium by (Jennings (1971))

$$\dot{\gamma} = \frac{299 v}{\sqrt{k\phi}}, \quad (4.112)$$

where v is in ft/day, k is permeability in darcies, and ϕ is porosity, fraction. Notice that the above equations are valid only over a limited range of the variables involved. The relative permeability to gas is similarly given by

$$k_{rg} = k_{rgo} (0.1 + 0.3092 v), \quad (4.113)$$

where k_{rgo} is relative permeability to gas in the absence of foam. This is a rough approximation, and only reflects the observed trend.

Auxiliary Relationships

Table 4.2 shows the functional dependences of the variables involved in the model. The functions employed for the majority of simulations are discussed below.

Oil Phase and Water Viscosity The oil phase viscosity μ_o was calculated from the Andrade equation for the Aberfeldy reservoir

$$\mu_o = 1.257 \times 10^{-5} \exp\left(\frac{5573}{T + 460}\right) \quad (4.114)$$

where T is in °F and μ is in cp, in the case where the other components were not soluble in the nonvolatile oleic phase. The oil viscosity-temperature relations used for the Aberfeldy and M-6 oils are shown in Figs. 4.3 to 4.6, on both semi-logarithmic and arithmetic coordinates. The Aberfeldy water viscosity curves are shown in Figs. 4.7 and 4.8.

Table 4.2

FUNCTIONAL DEPENDENCE OF PHYSICAL PROPERTIES

<u>Variable</u>	<u>Functional Dependence</u>
P_{cow}	S_w, T
P_{cgo}	S_g, T
k_{rw}	S_w, T
k_{rg}	S_g, T
k_{ro}	S_w, S_g, T
ρ_w	p_o, T, C_{iw}
ρ_g	p_o, T, C_{ig}
ρ_o	p_o, T, C_{io}
μ_w	T, C_{iw}
μ_g	T, p, C_{ig}
μ_o	T, C_{io}
M_g	C_{ig}
M_o	C_{io}
M_w	C_{iw}
k_h	Constant
ϕ	p
h_w	T, C_{iw}
h_g	T, C_{ig}
h_o	T, C_{io}
C_g	T, C_{ig}
C_o	T, C_{io}
C_w	T, C_{iw}
c_s	Constant
c_{ob}	Constant

ABERFELDY FIELD, SASKATCHEWAN

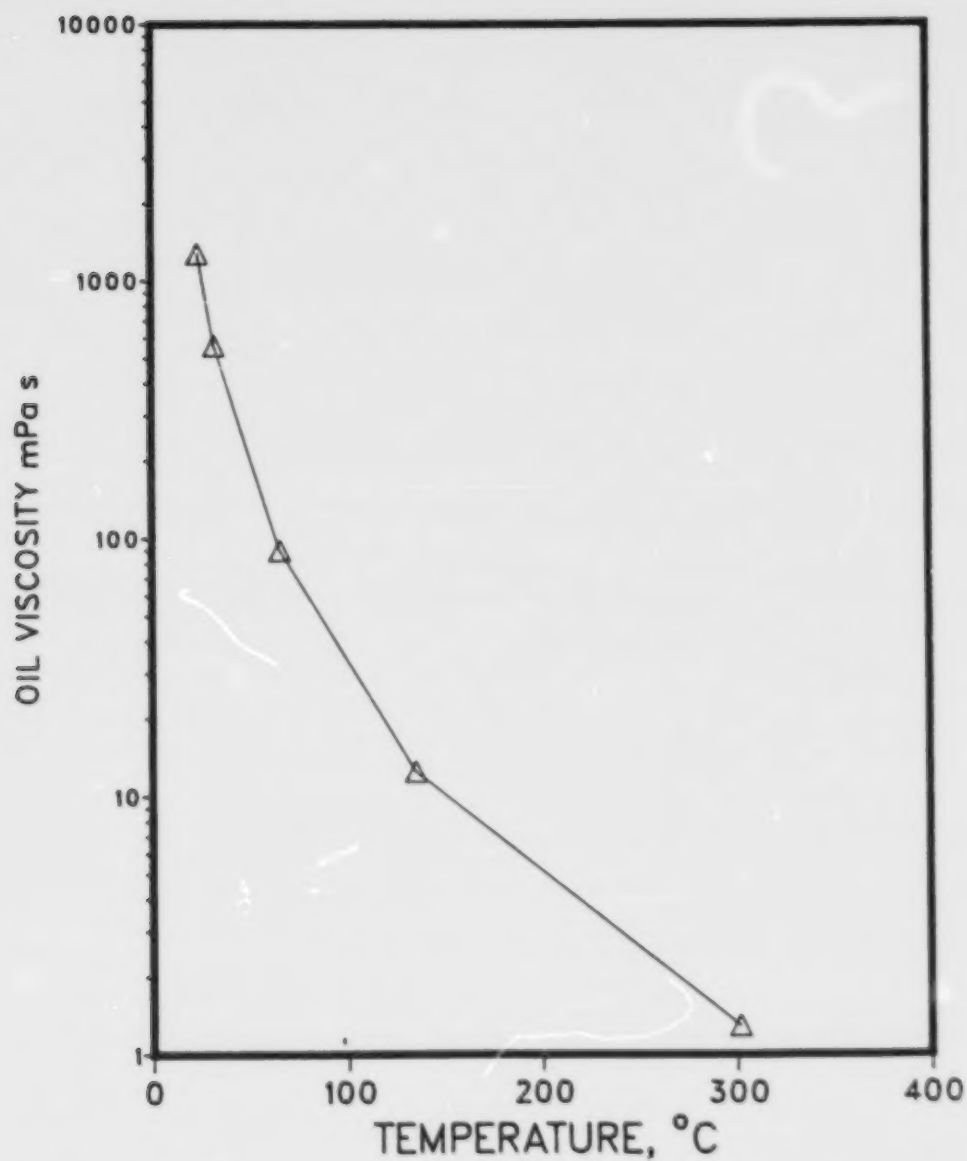


Figure 4.3 Aberfeldy Oil Viscosity-Temperature Relationship (log plot)

ABERFELDY FIELD, SASKATCHEWAN

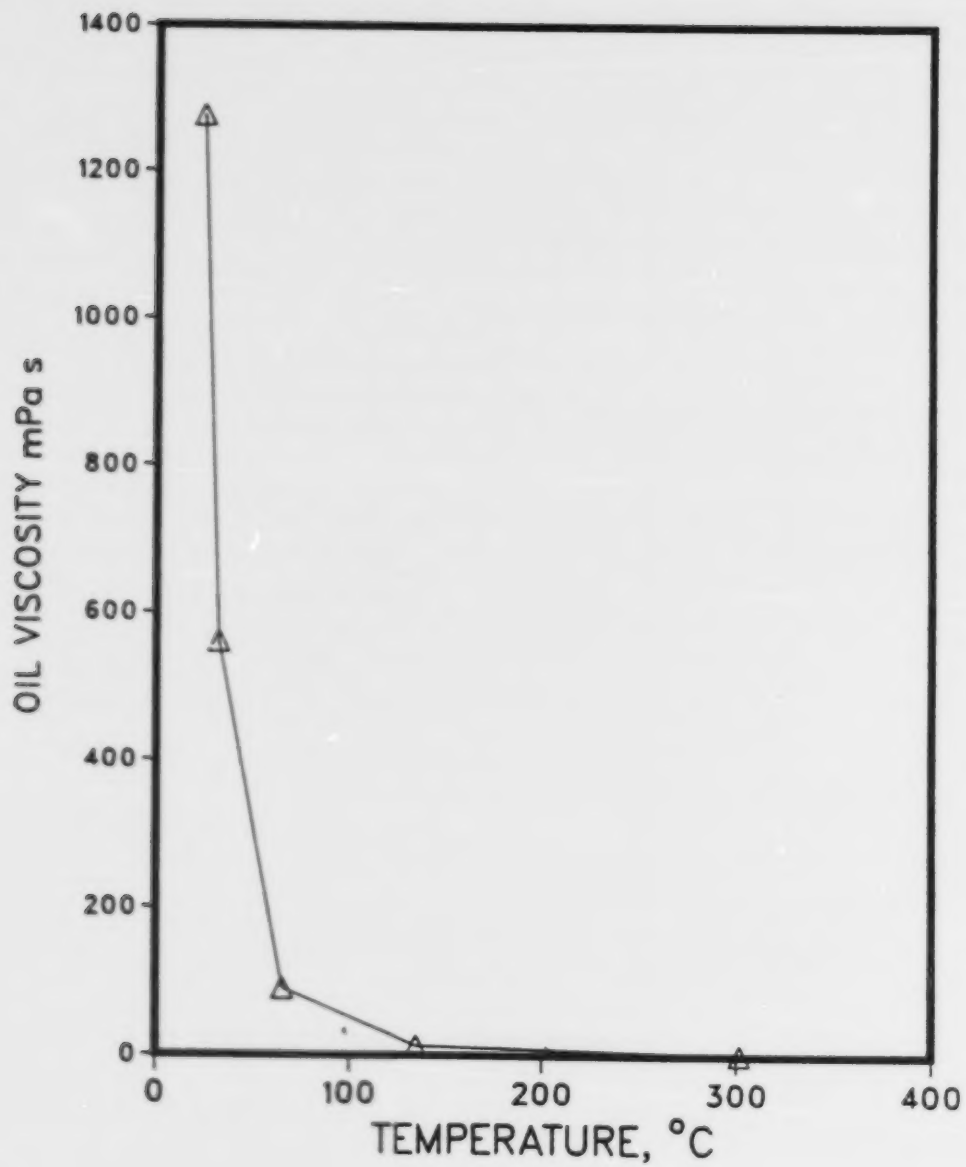


Figure 4.4 Aberfeldy Oil Viscosity-Temperature Relationship (linear plot)

M-6 FIELD, VENEZUELA

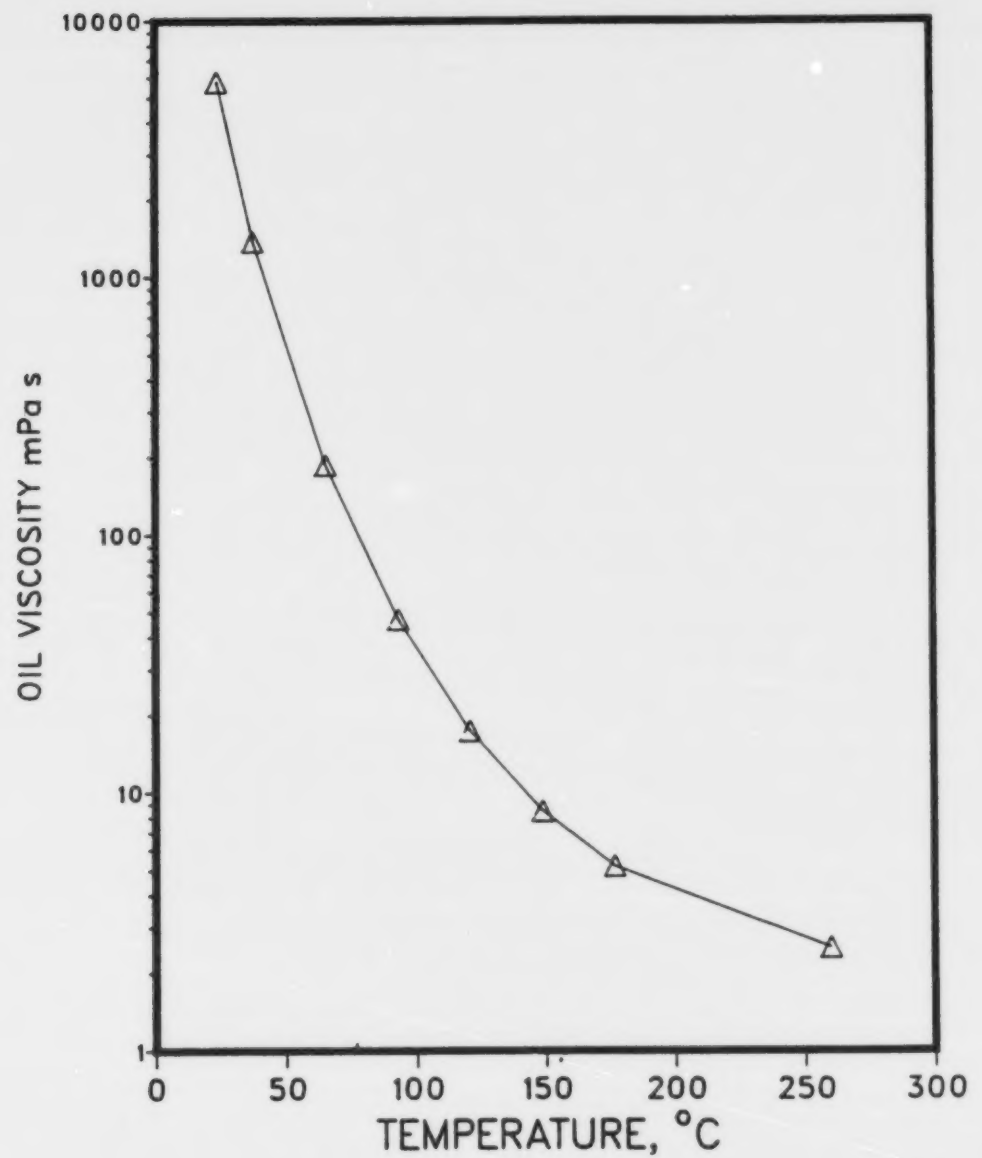


Figure 4.5 M-6 Oil Viscosity-Temperature Relationship (log plot)

M-6 FIELD, VENEZUELA

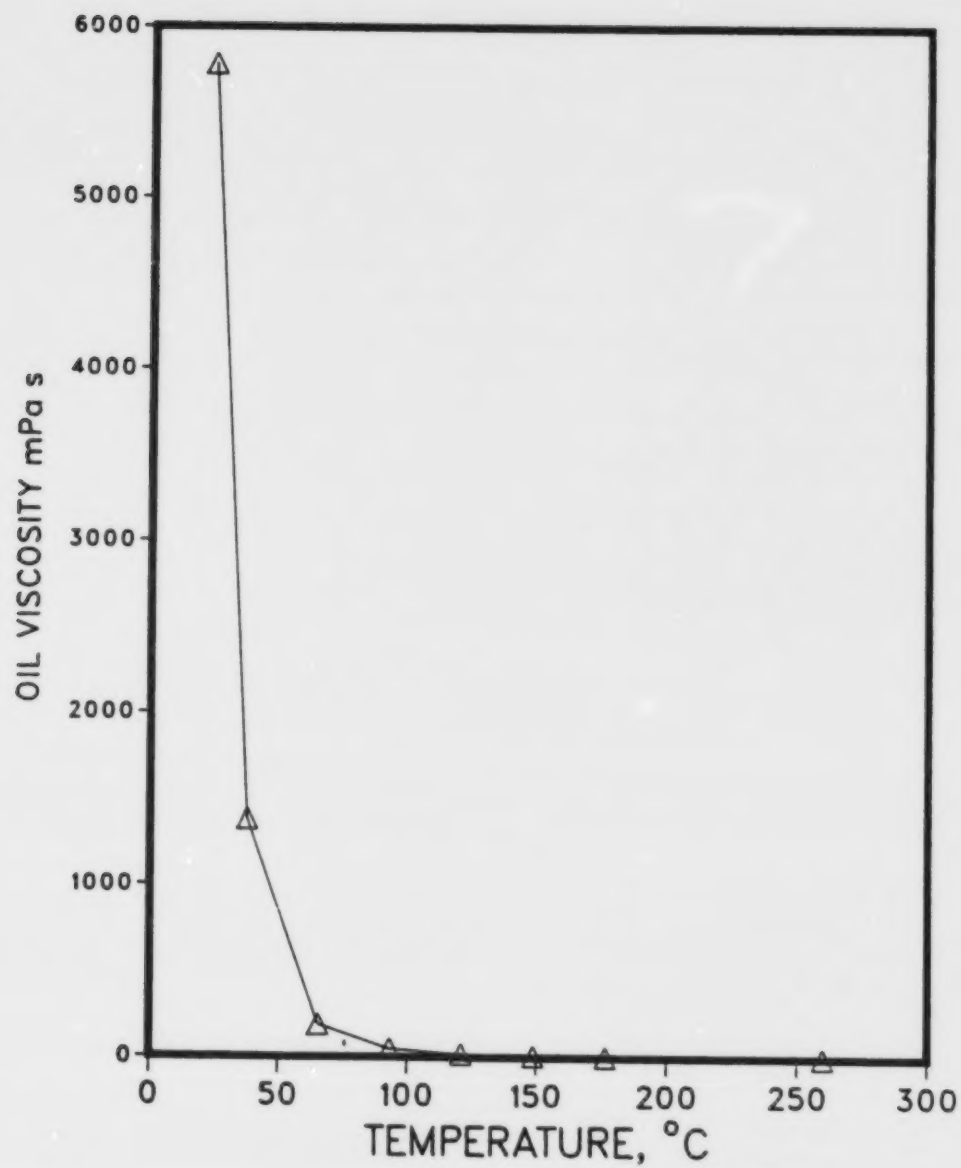


Figure 4.6 M-6 Oil Viscosity-Temperature Relationship (linear plot)

ABERFELDY FIELD, SASKATCHEWAN

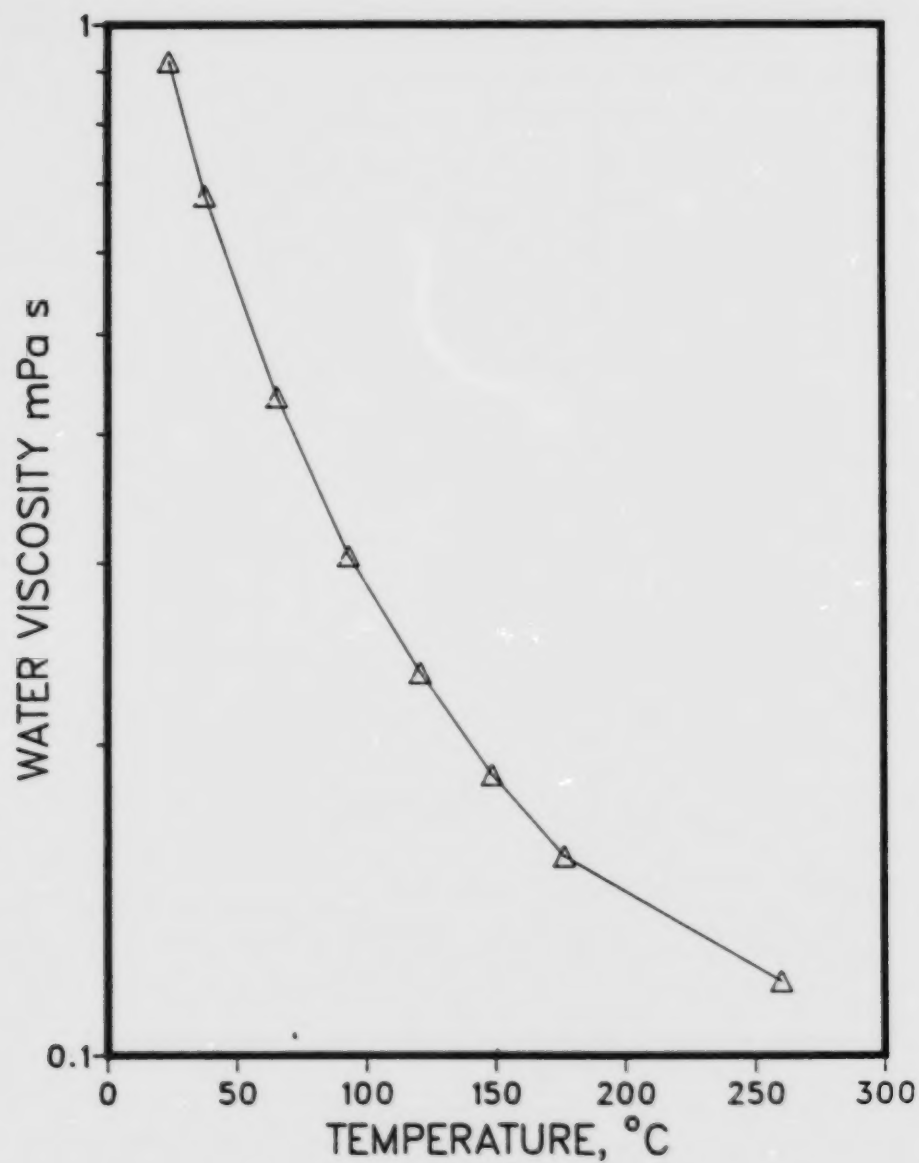


Figure 4.7 Aberfeldy Formation Water Viscosity-Temperature Curve

ABERFELDY FIELD, SASKATCHEWAN

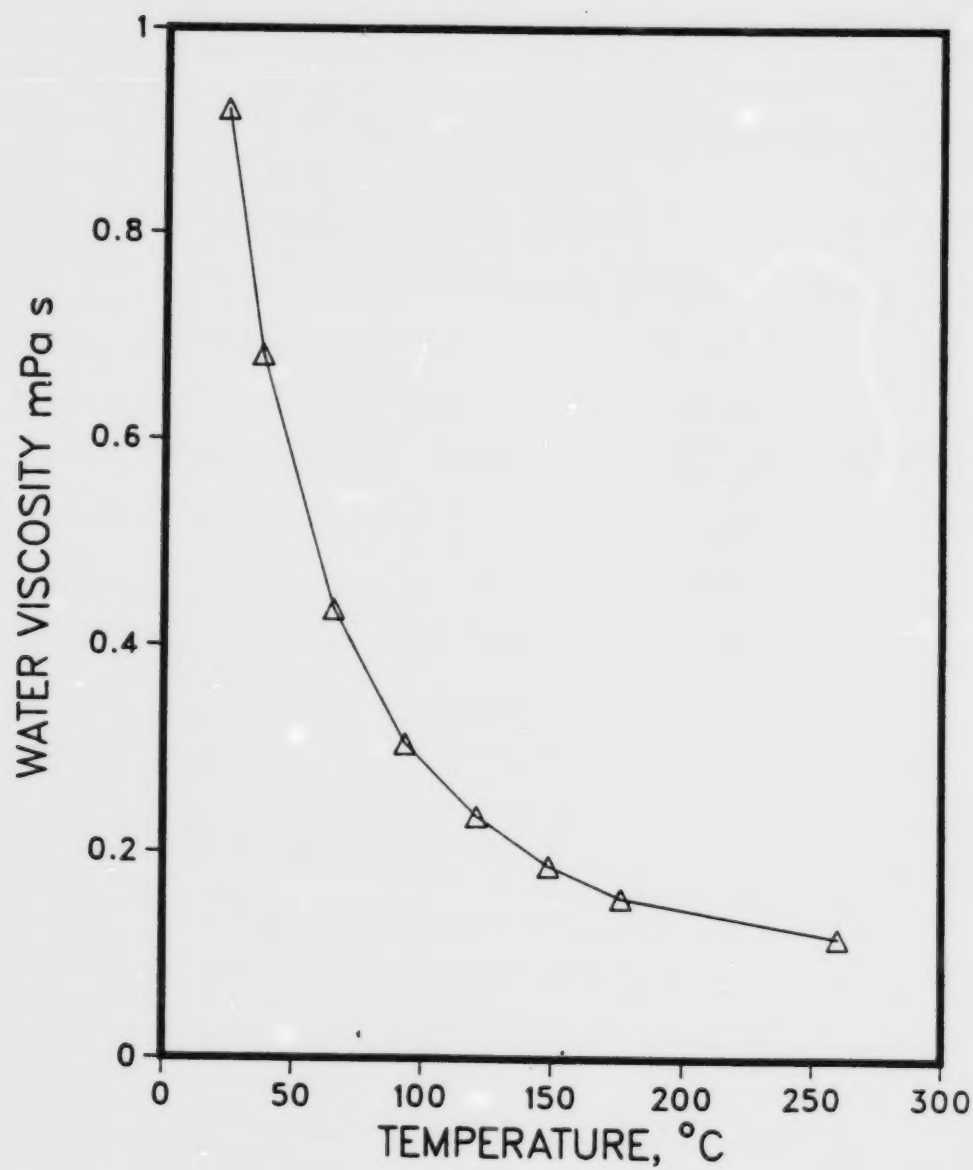


Figure 4.8 Aberfeldy Formation Water Viscosity-Temperature Curve

Non-Newtonian Oil Viscosity

Non-Newtonian oil viscosity is considered to be a function of temperature, pressure, gas solubility, and shear rate. The oil viscosity as a function of temperature is given by Andrade's equation, or Beggs and Robinson's (1975) correlation, if gas in solution is to be taken into consideration. Non-Newtonian oil viscosity was expressed by the following equation, which serves for illustrative purposes only:

$$\mu_o = \mu_{on}^n \dot{\gamma}^{n-1} \quad (4.115)$$

where μ_o is the apparent non-Newtonian viscosity. It is possible to determine whether a fluid exhibits non-Newtonian behaviour by giving a value of shear rate to Equation (4.115) that determines the oil viscosity. With flow in porous media, a range of shear rates occurs at any average throughput. An average shear rate $\bar{\dot{\gamma}}$ can be used to represent the shear rates that exist within each grid block in the reservoir corresponding to the block velocity. By using $\bar{\dot{\gamma}}$ and Equation (4.115), a non-Newtonian viscosity for the flowing fluid can be obtained, for the average velocity $\bar{v}$. The average velocity in a three-dimensional block is given by

$$\bar{v} = \frac{\bar{q}_o}{A\phi} \quad (4.116)$$

where $\bar{q}$ is the average flow rate in the block, i.e.,

$$\left(\frac{\bar{q}_o}{A} \right) = \left[\left(\frac{q_o}{A} \right)_{i+1, j, k} + \left(\frac{q_o}{A} \right)_{i-1, j, k} \right]^2 + \left[\left(\frac{q_o}{A} \right)_{i, j+1, k} + \left(\frac{q_o}{A} \right)_{i, j-1, k} \right]^2$$

$$+ \left[\left(\frac{q_o}{A} \right)_{i, j, k-1} + \left(\frac{q_o}{A} \right)_{i, j, k+1} \right]^2 \}^{1/2} \quad (4.117)$$

The characteristic length in the porous medium is defined by McKinley et al. (1966) to be:

$$l = C \sqrt{k/\phi} . \quad (4.118)$$

The constant C is related to the pore size distribution and tortuosity of the porous medium, and can be expressed as a function of permeability as follows (Gogarty, 1967):

$$l = f(k) \sqrt{k/\phi} . \quad (4.119)$$

The average shear rate, in this manner, can be obtained by dividing Equation (4.116) by Equation (4.119) as follows:

$$\dot{\gamma} = \frac{3.55 \bar{v}}{f(k) \sqrt{k/\phi}} , \quad (4.120)$$

where the functional form of $f(K)$ can be written as:

$$f(k) = \dot{m} \log \frac{k}{k_1} + \dot{P} \quad (4.121)$$

In the above equation, the constants $\dot{m}$ and $\dot{P}$ depend on the fluid properties for a given rock. In this study, $f(k)$ was taken to be unity (Gogarty (1967)). Equation (4.120) can be used to calculate the local shear rate in the porous medium, which is then substituted in Equation (4.115) to obtain the apparent viscosity at that point and time.

Relative Permeabilities and Capillary Pressures

The capillary pressure curve for the steam-oil system is shown in Fig. 4.9. This curve is unlike commonly used gas-oil curves, and is based upon laboratory data. Curves of this type have been employed by other investigators in steamflood simulations. The oil-gas and oil-water relative permeability curves are shown in Fig. 4.10 and 4.12, respectively. These are based upon typical Saskatchewan reservoir data, and are used for the Aberfeldy reservoir. The respective relative permeability ratio plots are shown in Figs. 4.11 and 4.13. The temperature dependence of capillary pressure was included by making endpoints temperature dependent (only in the case of M-6 simulations). The relative permeability curves were interpolated by means of splines.

Aqueous Phase Viscosity

The aqueous phase consists of water, a very small fraction of oil, and possibly a surfactant and salt. The viscosity of this mixture μ_w was approximated as follows:

$$\begin{aligned}\mu_w &= \mu_{w0} (1 + C) \\ &= (1 + C) \frac{1776 - T}{26.5 T - 89} ,\end{aligned}\quad (4.122)$$

where C is the concentration of the surfactant, μ_w is in cp and T is in °F. For most cases, the Aberfeldy water viscosity curves shown in Figs. 4.6 and 4.7 were used.

Vapour Phase Viscosity

The viscosity of the vapour phase mixture can be obtained from the Herning and Zipperer (1936) equation:

$$\mu_v = \frac{\sum \mu_i y_i \sqrt{M_i}}{\sum y_i \sqrt{M_i}} ,\quad (4.123)$$

where μ_i = pure component viscosity

ABERFELDY FIELD, SASKATCHEWAN

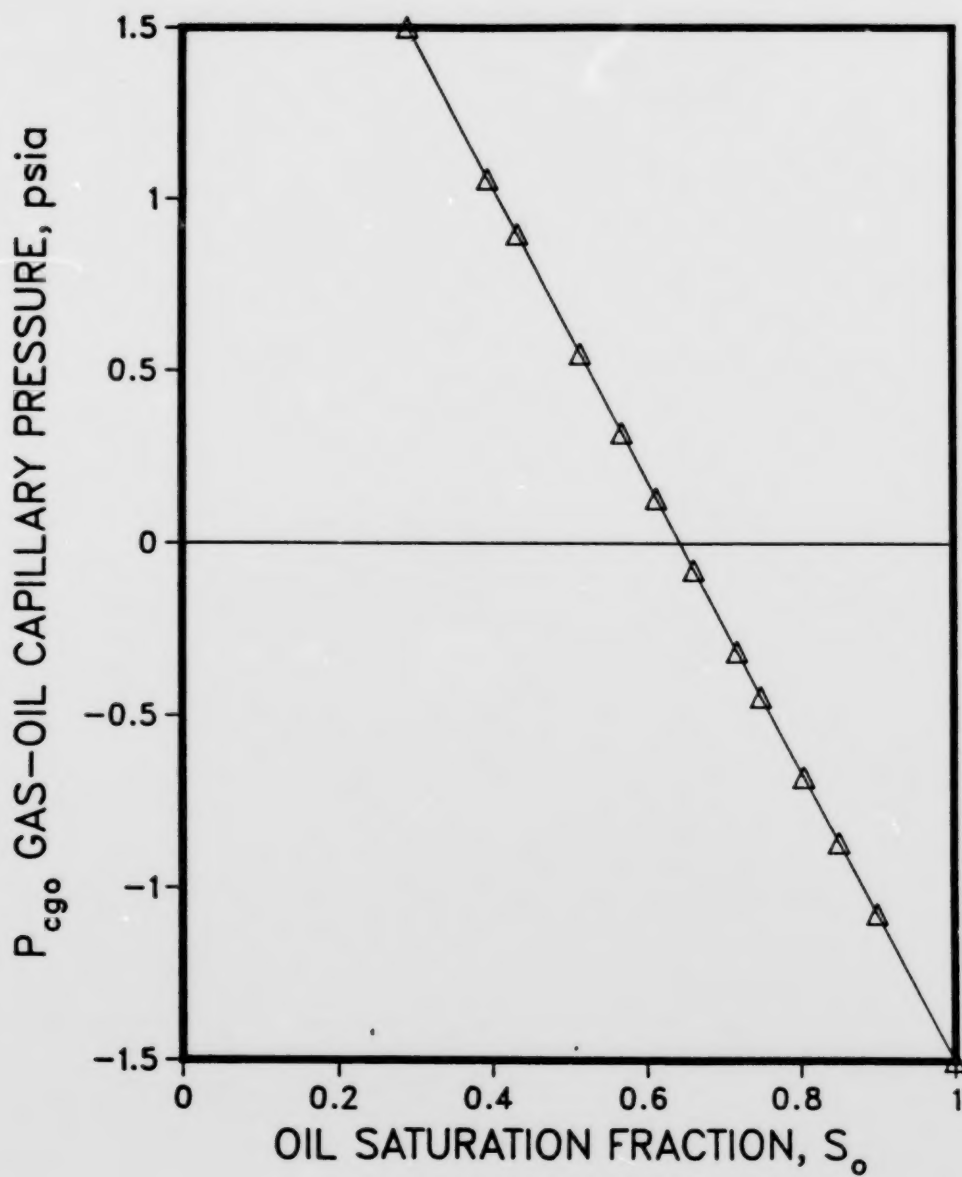


Figure 4.9 Formation Gas-Oil Capillary Pressure Relationship

ABERFELDY FIELD, SASKATCHEWAN

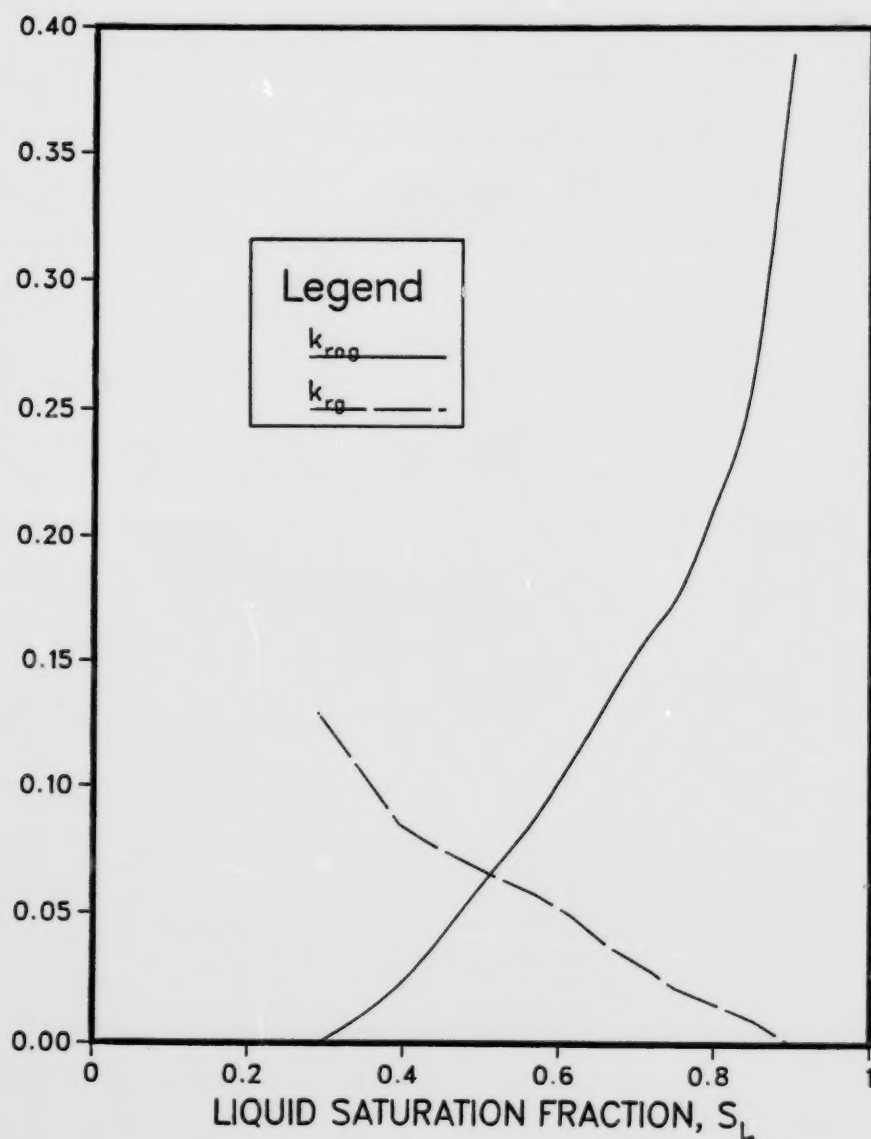


Figure 4.10 Aberfeldy Formation Gas-Oil Relative Permeability Curves.

ABERFELDY FIELD, SASKATCHEWAN

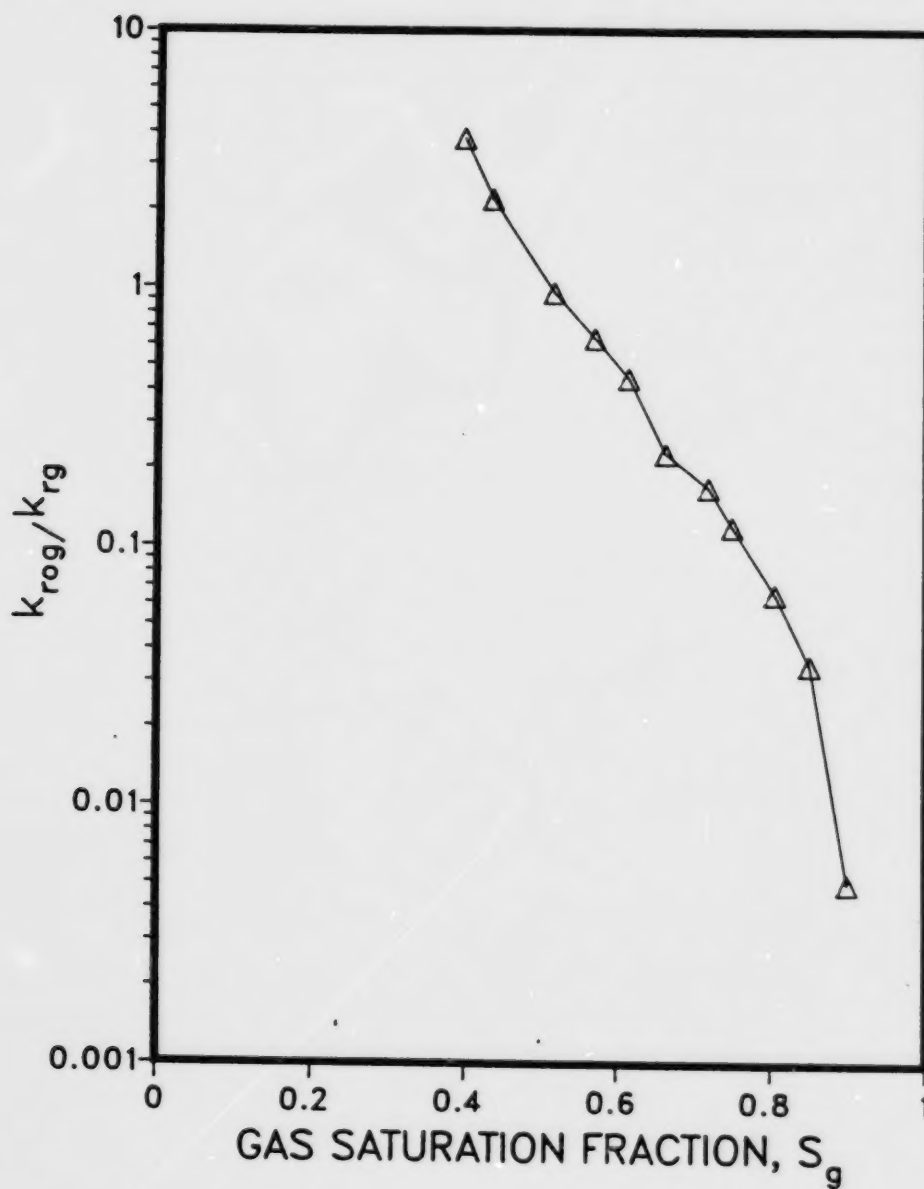


Figure 4.11 Aberfeldy Formation Gas-Oil Relative Permeability Ratio Curves

ABERFELDY FIELD, SASKATCHEWAN

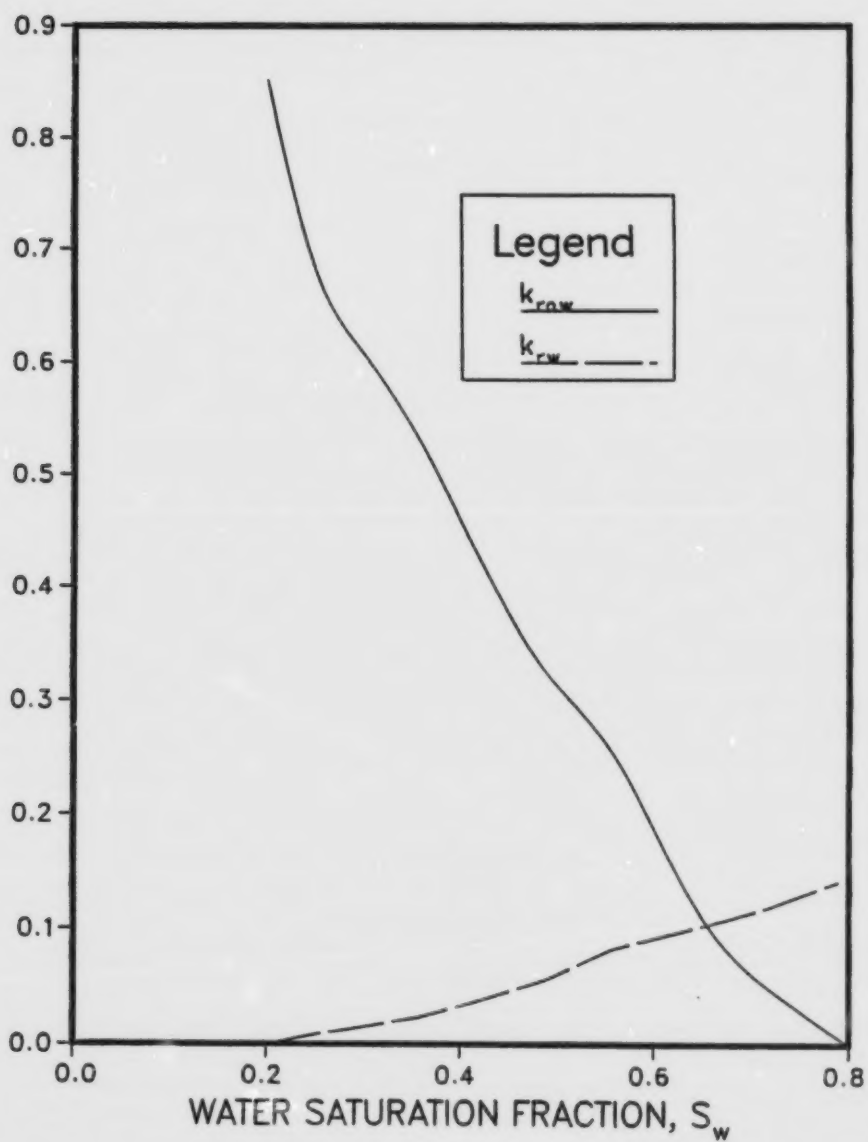


Figure 4.12 Aberfeldy Formation Water-Oil Relative Permeability Curves.

ABERFELDY FIELD, SASKATCHEWAN

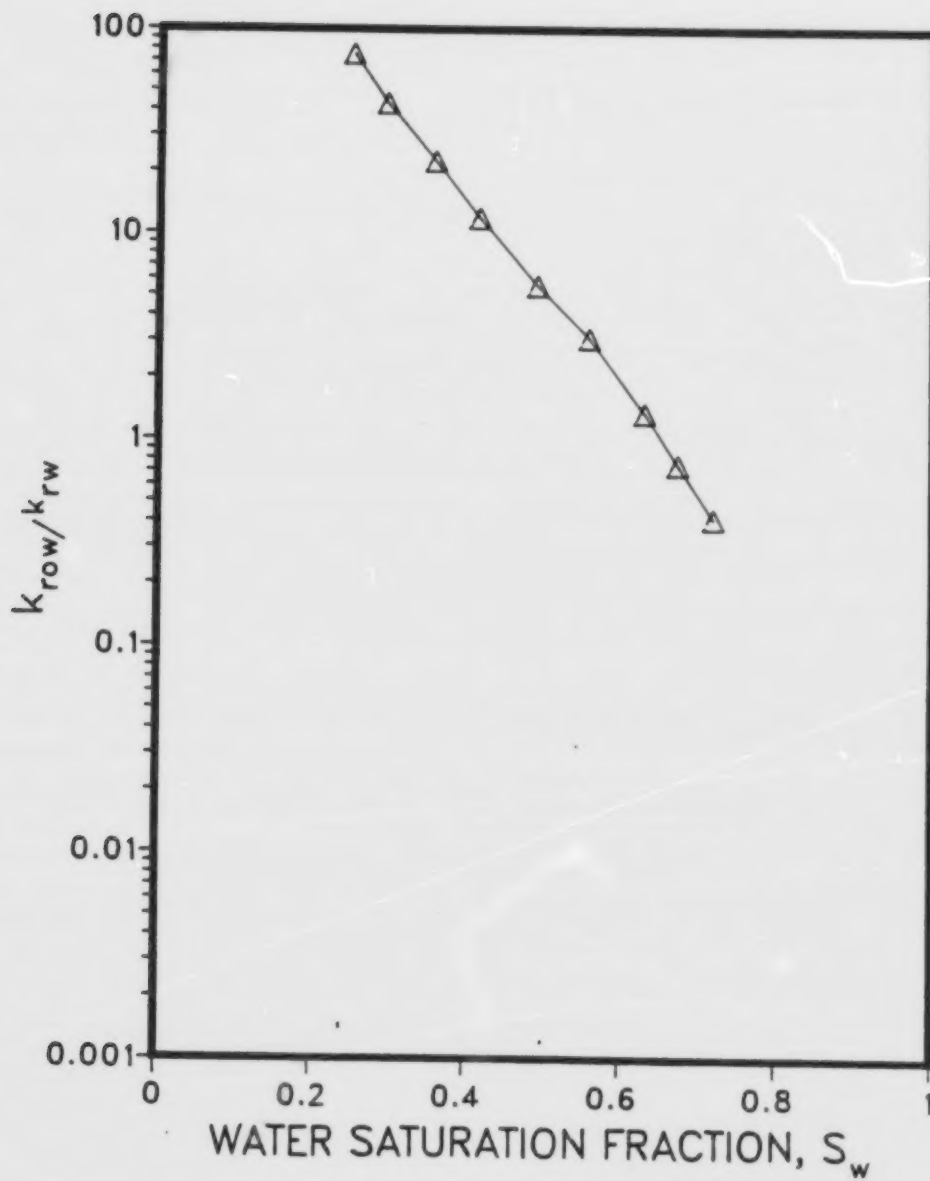


Figure 4.13 Aberfeldy Formation Water-Oil Relative Permeability Ratio Curves

M_i = pure component molecular weight

y_i = gas phase mole fraction of component i

Oil Phase Density

The density of the oil phase, ρ_o , was calculated from the following relationship, as a function of temperature and pressure (Crookston et al. (1979)):

$$\rho_o = (59.4 - 0.012 T) \exp (10^{-5} p) \quad (4.124)$$

where ρ_o is in lb/ft³, p_o is in psia, and T is in °F.

Aqueous Phase Density

The density of the aqueous phase, ρ_w , was calculated from the following relationship as a function of temperature and pressure:

$$\rho_w = (60.5 - 0.0171 T) \exp (0.004 p_w) \quad (4.125)$$

Equilibrium Factors

The mathematical treatment allows for as many as five components, being (1) nonvolatile hydrocarbon, (2) water, (3) surfactant, (4) noncondensable gas and (5) electrolyte. Since, in general, all components may be present in all phases, phase properties, such as molecular weights, can be expressed in terms of component properties. The equilibrium factors are defined as follows:

$$K_{iow} = \frac{x_{io}}{x_{iw}}, \quad (4.126)$$

$$K_{iog} = \frac{x_{io}}{x_{ig}}, \quad (4.127)$$

where K_{iow} is the equilibrium factor for oleic-aqueous phase, and K_{iog} for the oleic-vapour phase, x_{io} is the mole fraction of component i in the oleic phase, x_{iw} is the mole fraction in the aqueous phase, and x_{ig} is the mole fraction in the vapour phase. Equation (4.127) is the reciprocal of the usual two-component K -value, and was used in this form for convenience only. The model equations were developed in terms of mass fractions rather than mole fractions. Thus

$$K_{iow} = f_{iow} \frac{M_o}{M_w}, \quad (4.128)$$

where f_{iow} is the ratio of the mass fraction of the component i in the oleic and aqueous phases, M_o is the molecular weight of the oleic phase, and M_w is the molecular weight of the aqueous phase. The molecular weight is calculated from the phase compositions. Moreover f_{iow} is a function of temperature.

Properties of Steam

Many correlations are available for calculating properties of steam. The following correlations were used in this work. These were reported by Farouq Ali (1965) and Fiori and Ejiogu (1986).

Temperature

$$T_s = 115.1 p_s^{0.225} \quad (4.129)$$

where T_s is in $^{\circ}\text{F}$ and p_s is in psia.

Vapour enthalpy

$$h_s = 1204.8 - 0.000197697 (p - 453.23)^{1.73808}, \quad (4.130)$$

where h_s is in Btu/lb.

Liquid enthalpy

$$h_w = 77.036p^{0.28302} \quad 500 \leq p \leq 1500 \quad (4.131)$$

$$h_w = 0.12038p + 430.984 \quad 1500 \leq p \leq 2500 \quad (4.132)$$

where h_s and h_w are in Btu/lb.

Latent heat of water

$$L_{V_{H_2O}} = h_s - h_w, \quad (4.133)$$

where L_v is in Btu/lb.

Specific volume of steam, in ft³/lb

$$V_s = \frac{490.386 - 0.04703}{p} \quad (4.134)$$

Specific volume of liquid

$$V_w = 3.7175 \times 10^{-6} p + 0.01789 \quad (4.135)$$

The latter two values are valid if $500 \leq p \leq 1500$; these values will be

$$V_s = \frac{551.74}{p} - 0.0887 \quad (4.136)$$

$$V_w = 0.017529 \exp (1.9302 \times 10^{-4} p) \quad (4.137)$$

if $1500 \leq p \leq 2500$.

Wellbore Steam Flow Model

Formulation

The wellbore model developed for this study was designed to predict steam pressure (temperature), quality, and heat loss as functions of depth and time. The sand face steam pressure and quality were then input as functions of time into the steamflood simulator. The model is an improved version of an earlier model reported by Pacheco (1972).

The system to be modeled consists of three parts: (i) the fluid flow conduit, tubing or casing-tubing annulus, (ii) casing-tubing annulus, casing wall, and the cement sheath, and (iii) the formation surrounding the wellbore. Within the conduit, steady, homogeneous two-phase flow of water and steam is assumed. This is described by combining a two-phase mass balance with a momentum balance, and is as follows (the vertical coordinate z is taken positive in the downward direction):

$$144 \frac{dp}{dz} - \bar{\rho}_m \frac{g}{g_c} + \bar{\rho}_m \frac{dW_f}{dz} + \frac{\bar{\rho}_m v_m}{g_c} \frac{dv_m}{dz} = 0 \quad (4.138)$$

The subscript m in the above equations refers to the steam-water mixture.

The pressure gradient is given by

$$\frac{dp}{dz} = \frac{1}{144} \left(\frac{\bar{\rho}_m \frac{g}{g_c} - \tau_f}{1 - \gamma_a} \right), \quad (4.139)$$

where γ_a is the acceleration gradient defined in the manner of Orkiszewski (1967):

$$\gamma_a = \frac{w q_s}{144 A^2 g_c \bar{p}} \quad (4.140)$$

Next, an energy balance is written for the flow under consideration, which is as follows:

$$\frac{\dot{Q}}{3600} + w \frac{d}{dz} \left(h_m + \frac{v_m^2}{2g_c J_c} - \frac{g}{g_c J_c} z \right) = 0, \quad (4.141)$$

where the enthalpy h_m of a two-phase steam-water mixture is given by

$$h_m = h_m(f_{st}, p) = (1 - f_{st})h_w + f_{st}h_s, \quad (4.142)$$

where f_{st} is steam quality, and h_w and h_s are enthalpies of saturated water and steam, respectively. These were calculated from the equations given in the previous section. Using these equations, and allowing for heat loss from the tubing to the cement sheath, given by

$$\dot{Q} = 2\pi r_{te} U_{te} (T - T_{cem}), \quad (4.143)$$

the energy balance equation (4.141) takes the form

$$C_1 \frac{df_{st}}{dz} + C_2 f_{st} + C_3 = 0. \quad (4.144)$$

Here U_{te} represents the net resistance to heat flow offered by the flowing fluid, tubing, insulation, annulus fluid, casing wall, and the cement sheath, and is given by

$$U_{te} = \frac{1}{r_{te}} \left[\frac{\ln \frac{r_{cem}}{r_{ins}}}{k_{hins}} + \frac{1}{r_{ins}(h_r + h_c)} + \frac{\ln \frac{r_{cem}}{r_{ce}}}{k_{hcem}} \right]^{-1}. \quad (4.145)$$

In the above equations the subscript "cem" refers to the cement sheath, "ins" refers to tubing insulation, if any, "ce" refers to casing exterior, and "te" refers to tubing exterior. The coefficients h_r and h_c are radiation and convection heat transfer coefficients, calculated in the conventional manner, as described by Pacheco (1972).

The heat loss term $\dot{Q}$ was calculated by solving the two-dimensional radial heat conduction equation

$$\frac{1}{r} \frac{\partial}{\partial r} \left(r \frac{\partial T_f}{\partial r} \right) + \frac{\partial^2 T_f}{\partial z^2} = \frac{1}{\alpha} \frac{\partial T_f}{\partial t}, \quad (4.146)$$

where T_f is the temperature of the surrounding formations and α is thermal diffusivity. This is a new feature; the previous authors have used the approximation of the Ei -function to estimate the temperatures around the wellbore, and thus derive the heat loss rate.

The boundary and initial conditions for the solution of Eqs.(4.139) and (4.141) are:

$$\text{Initial Condition} \quad T_f = T_a + \gamma z \quad \text{at} \quad t = 0$$

$$\text{Boundary Conditions} \quad T_f = T_a \quad \text{at} \quad z = 0$$

$$T_f = T_R \quad \text{at} \quad z = Z$$

$$\dot{Q} = -2\pi r k_{hf} \frac{\partial T_f}{\partial r} \quad \text{at} \quad r = r_{cem}$$

$$\frac{\partial T_f}{\partial r} = 0 \quad \text{at} \quad r = \infty$$

Two-Phase Flow

The existing two-phase flow literature shows that the prevailing flow regime should be considered in determining holdup (and hence the average mixture density) and the friction factor. The following flow regimes were considered, using the correlations given by the authors indicated:

<i>Flow Region Considered</i>	<i>Correlation</i>
Bubble/Plug	Gould et al (1974)
Slug/Froth	Chierici et al (1974)
Transition	Duns and Ros (1961)
Mist	Duns and Ros (1961)

Solution Procedure

Equations (4.139) and (4.144) are ordinary differential equations. They were differenced and solved by a procedure similar to that discussed by Pacheco (1972). Equation (4.146) was discretized and solved using the backward difference (implicit) scheme. The resulting algebraic equations were solved by a band algorithm. The overall procedure was iterative, which involved updating the nonlinear coefficients and the heat transfer coefficient U_{te} at each iteration.

Chapter V

DEVELOPMENT OF THE COMPUTER MODEL

This chapter will discuss the computer program development and the structure of the computer code. The main sections of the program are discussed in detail in the following paragraphs. The program consists of a main code and two subroutines. The first subroutine calculates the fluid properties and all time-dependent transmissibilities, while the second one solves the block-banded system of linear equations resulting from the Newtonian iteration. The number of subroutines was minimized in order to reduce computational time. The program flow diagram is shown in Fig. 5.1. The program requires total memory of approximately 2 Megabytes.

Initialization

As the first step, the block data program is set to initialize all of the transmissibilities, constant as well as time-dependent. It also initializes all the source-sink terms for heat as well as fluid flow. The main program reads all of the basic data and initializes the remaining variables. An initial time step is read in; afterwards, the program selects its own time step automatically within minimum and maximum limits that are specified. The program has the flexibility of either using a single value of each variable for the entire grid, or values for the individual grid blocks.

Calculation of Transmissibilities

Before starting the calculations for a new time step, all of the time-invariant quantities are calculated, which include constant parts of the heat flow, fluid flow and diffusional transmissibilities. The time-dependent parts of the transmissibilities are calculated at each time step and are updated within each iteration.

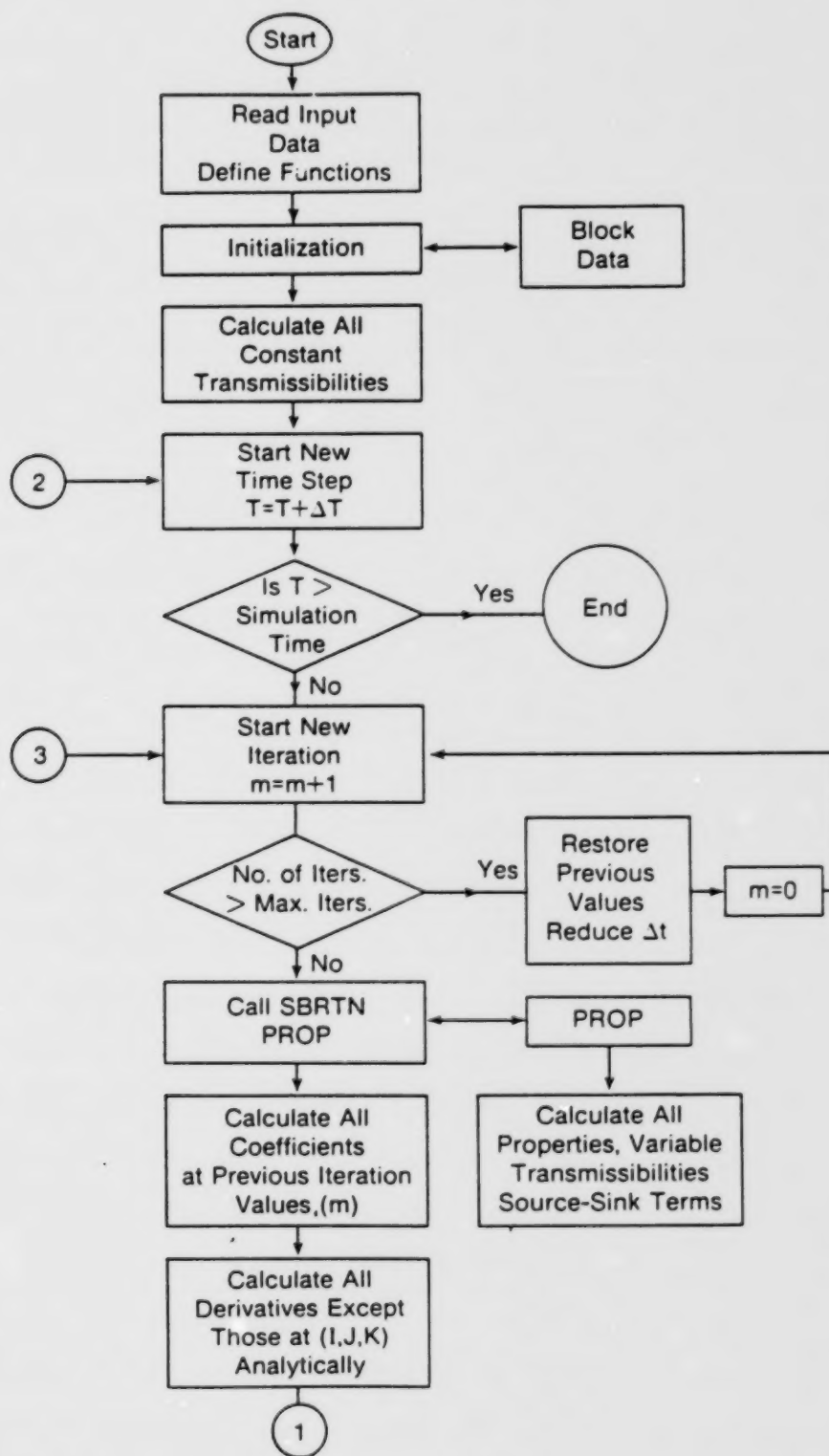


Figure 5.1 Flow Diagram of the Computational Procedure Used in the Program

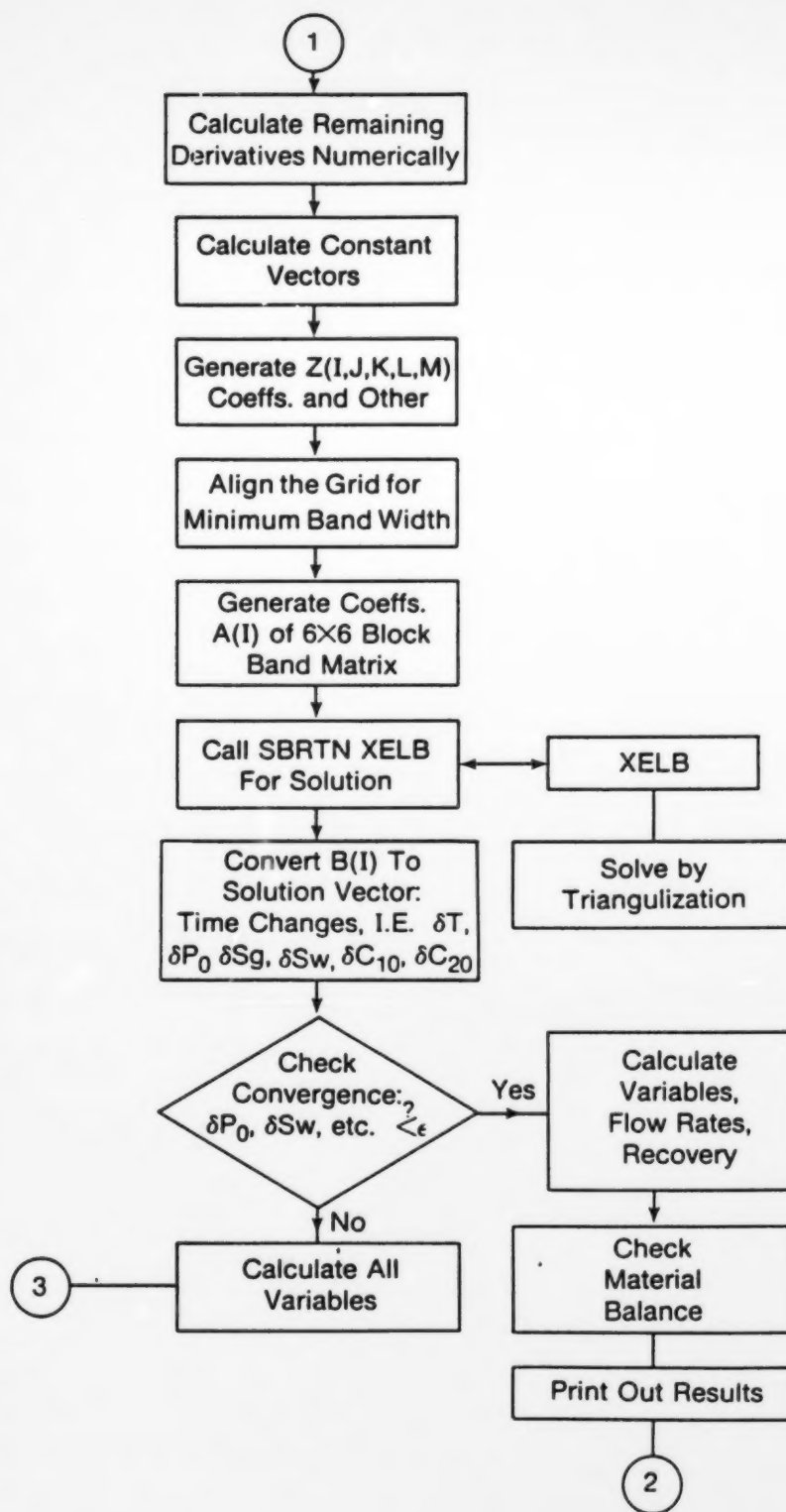


Figure 5.1 (continued) Flow Diagram of the Computational Procedure Used in the Program.

Property Subroutine

The main feature of this program is a subroutine named PROP. Once this subroutine is called, it provides the values of all of the fluid properties, their derivatives, and the coefficients. The time-dependent parts of all variables are calculated in this subroutine and multiplied by the constant parts transferred from the main program.

The property subroutine also calculates the fluid and heat source/sink terms, using the given well specifications. These are based upon the time level $(n+1)$ transmissibilities. The subroutine computes all arrays of derivatives of the basic properties, such as viscosity and density. Finally, it calculates a variety of summations involving transmissibilities as well as derivatives.

Calculation of Coefficients

The coefficients Z , B , D , E , F , H , and S in the linearized Newtonian equations are long expressions, involving various derivatives and other properties. The derivatives of the mass balance equations and the heat balance equations, written in functional form, were derived analytically with respect to the variables at blocks $(i \pm 1, j, k)$, $(i, j \pm 1, k)$, and $(i, j, k \pm 1)$. The analytical derivatives at block (i, j, k) were more tedious to obtain. The analytical expressions obtained were so lengthy that it was decided to calculate them numerically. It is believed that the numerical calculation of the derivatives led to considerable savings in computer time. Numerical calculation of derivatives can be simplified, resulting in reducing computer time, by eliminating terms in the function which do not depend on the variable of differentiation. Finite difference approximation of the convective-diffusion terms was mentioned in the previous chapter, and is given in Appendix A.

The coefficients Z , B , D , E , F , H , and S in the equations involve the above-mentioned derivatives as well as other variables. The first five equations are mass balances

for components 1 to 5, the sixth equation being the energy balance. Each equation involves six Z coefficients, six B coefficients, etc. The program generates the Z, B, D, F, H, and S coefficients, first, for the mass balance equations, and then for the energy balance. The E coefficients are calculated next in the same order. This permits writing a more efficient computer code, since the computation of coefficients is linked with the generation of analytical or numerical derivatives, as the case may be. The constant vectors for the equations are generated together with the coefficients, in the same order. The final matrix of coefficients is of the form shown in Fig. 5.2 for a $3 \times 3 \times 2$ grid.

Solution of the System of Equations

The system of linear equations to be solved at each iteration toward the new time level values consists of six times the number of grid blocks. The coefficient matrix of the equations is shown in Fig. 5.2. As can be seen, it has a block diagonal structure. The solution can be obtained by Gaussian elimination or other solution techniques. In this study, it was decided to use a band algorithm, which was modified for a block diagonal matrix. This modification is quite tedious, because the transformed matrix must preserve a certain structure. Figure 5.3 shows the transformed matrix. The listing of the program developed for transforming the original block coefficient matrix of any order into a block diagonal matrix of minimum band width is given in Appendix B. It is believed that this program could be useful for any similar system of simultaneous equations arising from an implicit scheme. The program also includes the solution algorithm, which is a band matrix solver, with limited pivoting. The matrix transformation and band solver programs were extensively tested, by themselves, and were also used in a black oil simulator to ensure accuracy of solution.

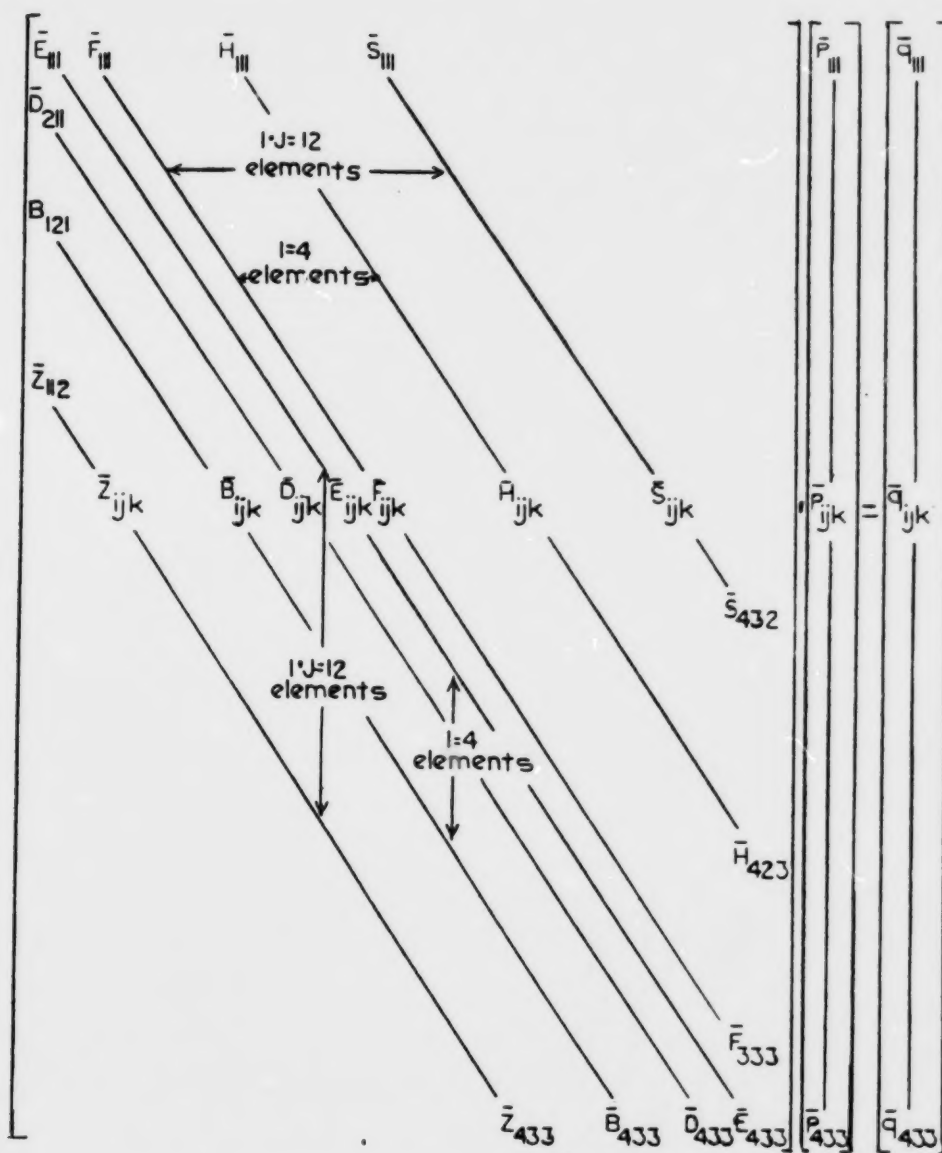


Fig. 5.2 - Matrix Form of the System of Equations, Where Each Element is a 6x6 Matrix.

ROW	FIRST	LAST	TOTAL
1	121	121	80
2	122	122	80
3	123	123	80
4	124	124	80
5	125	125	80
6	126	126	80
7	127	127	80
8	128	128	80
9	129	129	80
10	130	130	80
11	131	131	80
12	132	132	80
13	133	133	80
14	134	134	80
15	135	135	80
16	136	136	80
17	137	137	80
18	138	138	80
19	139	139	80
20	140	140	80
21	141	141	80
22	142	142	80
23	143	143	80
24	144	144	80
25	145	145	80
26	146	146	80
27	147	147	80
28	148	148	80
29	149	149	80
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32	152	152	80
33	153	153	80
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37	157	157	80
38	158	158	80
39	159	159	80
40	160	160	80
41	161	161	80
42	162	162	80
43	163	163	80
44	164	164	80
45	165	165	80
46	166	166	80
47	167	167	80
48	168	168	80
49	169	169	80
50	170	170	80
51	171	171	80
52	172	172	80
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64	184	184	80
65	185	185	80
66	186	186	80
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82	202	202	80
83	203	203	80
84	204	204	80
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104	224	224	80
105	225	225	80
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107	227	227	80
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111	231	231	80
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113	233	233	80
114	234	234	80
115	235	235	80
116	236	236	80
117	237	237	80
118	238	238	80
119	239	239	80
120	240	240	80
121	241	241	80
122	242	242	80
123	243	243	80
124	244	244	80
125	245	245	80
126	246	246	80
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Overall Procedure

The overall solution procedure is illustrated by the program flow diagram shown in Fig.5.1. Briefly, the program first calculates the time-invariant quantities, such as constant parts of the several transmissibilities involved in the equation. The calculation of the main dependent variables, i.e. p_o , S_w , S_g , T , C_{1o} and C_{2o} at the new time level requires Newtonian iteration, which is done in an inner iteration loop. For this purpose, the derivatives, as well as all other time-dependent variables, are calculated at the latest iterates of the new time values of the variables. These are used to generate the coefficients Z , B , D , E , F , H , S , and the constant vectors in all of the equations.

Next, the coefficient matrix is transformed into a block band matrix, which is then solved by a band algorithm. The solution gives the changes in the values of the variables over one iteration, i.e. $\delta p_o^{(m)}$, $\delta S_w^{(m)}$, $\delta S_g^{(m)}$, $\delta T^{(m)}$, $\delta C_{1o}^{(m)}$ and $\delta C_{2o}^{(m)}$, where m indicates the iteration level. These are tested for convergence. If convergence is achieved, the final values of the variables at the new time level are calculated. If convergence is not attained, the derivatives and the coefficients are recalculated, and the procedure is repeated. The solution is advanced to the desired simulation time. The grids used in the simulations are shown in Fig. 5.4.

Computational Details

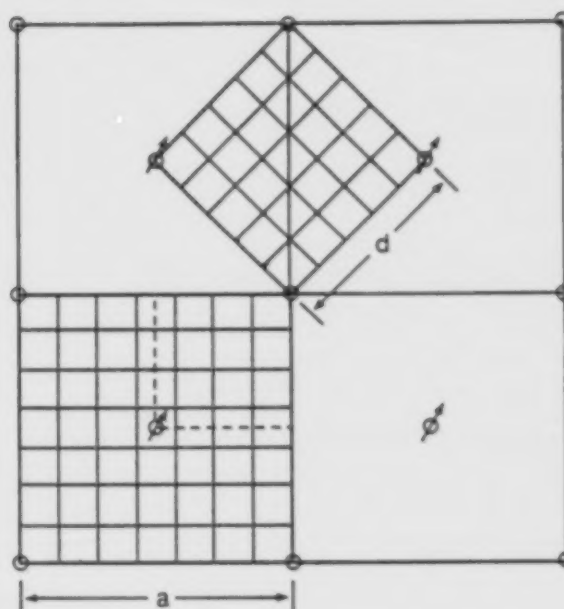
The program requires a memory of approximately 2 Megabytes for a $5 \times 5 \times 2$ grid. The number of simultaneous equations to solve in this case is 300, which alone takes 11 seconds of CPU time amounting to approximately 2 mllisec/grid block/time step. This is rather slow, even for the coarse grid used. The machine time can be reduced through the use of two dimensions and/or fewer number of components. For large grids necessary for commercial simulations, the code must be adapted for a supercomputer.

Grid II

Diagonal grid Areas
Shown is $A/2 = d^2$

Grid III

Diagonal grid Pattern
Area A



Grid I

Pattern position chosen
to conform with the
grid in parallel orientation
Pattern Area A

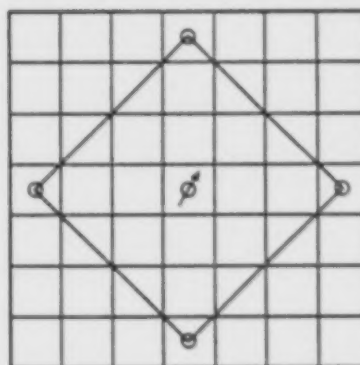


Figure Grids used in the steamflood and cyclic steam stimulation simulations.

Figure 5.4 Types of Grids used in the Simulations

The three-phase, three-dimensional model was validated using the Test Problem 1 given by Coats (1976). The oil, water, and gas saturation distributions and pressure distribution at 1800 days were within 5% of the values quoted. The cumulative oil recovery was 67% vs 66.4%. It can be said that the simulator is valid for at least one previously studied problem. The material balance and the heat balance errors at all times were less than 0.1%, and much smaller in most cases.

DISCUSSION OF RESULTS

Introduction

This numerical study of steam injection examines steam injection processes in the contexts of foam injection, additive gas, thermal upgrading, and non-Newtonian oil viscosity behaviour; it evaluates the effect of bottom water on steamflooding and cyclic steam stimulation response, with particular attention to partial penetration, and examines the effect of multiple steam offtake from the injection tubing on steamflood response. These are the principal contributions of this work, and are believed to represent new information.

In the following discussion, sample results are presented for each of these aspects of steam injection. The objective is to study the effect of these phenomena in a steam injection simulator, and to provide an idea of the relative importance and magnitudes of such effects. It is not possible to discuss these in depth because of time and other constraints, one of which is the computer time available.

Simulators Developed

Three steam simulators were employed over the period of this study. The fully implicit five-component three-dimensional three-phase simulator was extremely slow, limited to short runs. The other two simulators, viz. three-dimensional two-component and two-dimensional four-component three-phase simulators were used for the runs discussed here. In particular, the first of these simulators was successful in simulating virtually every steam injection situation, with regard to solution stability and fast convergence. Even then a short simulation (e.g. 3 years) consumed over 500 seconds of CPU time.

For wellbore simulations, a wellbore heat loss model was extended for flow regime considerations in the tubing, and in particular, multiple offtake of steam, which has not been simulated heretofore.

Reservoir Data Employed for the Simulations

Three different heavy oil reservoirs were considered in this work: Aberfeldy, Saskatchewan; M-6, Venezuela; and Cold Lake, Alberta. The data used for these simulations are given in Table 6.1. The relative permeability and viscosity-temperature curves are shown in Figs. 4.3 to 4.13. The methods used for foam upgrading, and non-Newtonian oil implementation were described in Chapter IV. The formation thicknesses given in Table 6.1 are realistic for the reservoirs considered. In one or two cases, other thicknesses were also used in order to be able to compare the results. The bottom water thickness varies from zero to equal to the oil zone thickness, because the objective was to examine the effect of bottom water. It is possible to make certain rock properties, such as compressibility, specific heat, thermal conductivity and thermal diffusivity functions of the variables involved, in the simulators. However, this was considered to be unnecessary because of the uncertainty in the data available. Similar considerations hold for the parameters used in the thermal upgrading, foam, and non-Newtonian oil viscosity models, where even less consistent information has been published.

The grids used were coarse, ranging from 18 to 200 grid blocks, in view of the excessive CPU time required for finer grids, particularly because in the fully implicit scheme, three to six equations are solved for each block. A few runs were repeated for short durations using finer grids. The discrepancy in computed oil recoveries was less than 5%, and in oil saturations, etc., less than 10%, for grid size change from 18 to 147 grid blocks.

Types of Simulations Conducted

Several types of simulations were carried out for this study. These are summarized pictorially in Fig. 6.1. Detailed results are given in the tables in Appendix C. It is seen that not all runs were repeated for all three reservoirs considered, because the purpose was to

Table 6.1
RESERVOIR DATA USED IN THE SIMULATIONS

	Aberfeldy Saskatchewan	Cold Lake Alberta	M-6 Venezuela
Formation thickness, ft	36	36 to 150	98
Water zone thickness, ft	3.6 to 36	3.6 to 36	9.8 to 98
Formation permeabilities, darcy			
k_x	2.0	2.0	2.0
k_y	2.0	2.0	2.0
k_z	0.4 to 2.0	2.0	0.4 to 2.0
Porosity, %	35	35	35
Reservoir pressure, psi	200	500	150
Reservoir temp, °F	74	74	113
Oil viscosity at reservoir temp, cp	1275	125,000	5780
Water compressibility, psi^{-1}	3×10^{-6}	3×10^{-6}	3×10^{-6}
Water thermal expansion coeff., $^{\circ}\text{F}^{-1}$	4.9×10^{-4}	4.9×10^{-4}	4.9×10^{-4}
Oil compressibility, psi^{-1}	5×10^{-6}	5×10^{-6}	5×10^{-6}
Oil thermal expansion coeff., $^{\circ}\text{F}^{-1}$	5×10^{-4}	5×10^{-4}	5×10^{-4}
Rock compressibility, psi^{-1}	1×10^{-4}	1×10^{-4}	1×10^{-4}
Formation thermal conductivity, $\text{Btu/hr-ft-}^{\circ}\text{F}$	1.76	1.76	1.76
Overburden thermal conductivity, $\text{Btu/hr-ft-}^{\circ}\text{F}$	1.47	1.47	1.47
Overburden density, lb/ft^3	165	165	165
Overburden specific heat, $\text{Btu/lb-}^{\circ}\text{F}$	0.20	0.20	0.20
Overburden thermal diffusivity, ft^2/hr	0.04	0.04	0.04
Relative permeabilities	Figs. 4.10 and 4.12	→	→
S_{wc} , fraction	0.20	0.20	0.20
S_{or} , fraction	0.211	0.211	0.211
S_{gc} , fraction	0.1	0.1	0.1

Types of Simulations Conducted

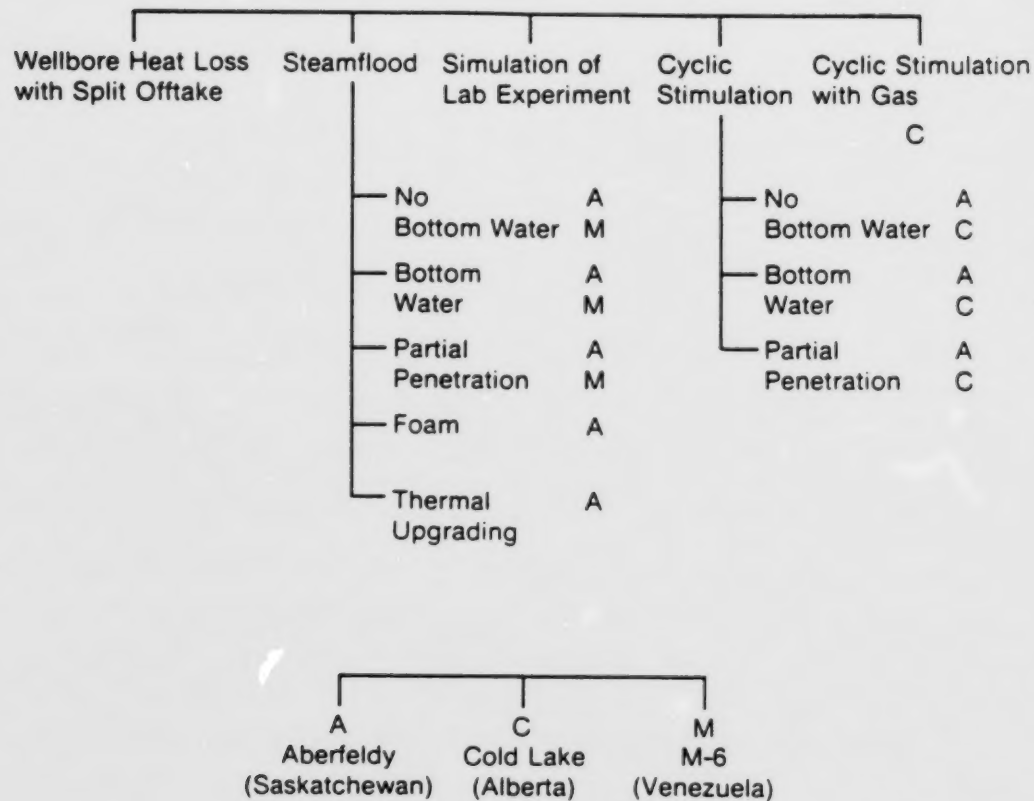


Figure 6.1 Diagram Showing the Types of Simulations Conducted in this Study

show the effects of differences in reservoir characteristics on the steam injection process under consideration. It is seen that a large number of simulations were made in the case of Aberfeldy reservoir, because of the importance of bottom water in this type of reservoir. The runs were more computer time-consuming in the case of the Clearwater formation, Cold Lake, due to very high oil viscosity, which limited the number of runs. No computational difficulties were encountered in any of the cases studied. At times, the automatic time step selection procedure produced very small time steps (order of 0.005 day), which increased the CPU time.

Base Steamflood for Aberfeldy

The base steamflood results for the Aberfeldy reservoir (ABRS1) are listed in Table 6.2, and plotted in Figs. 6.2 to 6.4. Selected time results are given in Table C.1. A 20-acre five-spot pattern was considered in this run, with a steam injection rate of 600 B/D CWE (CWE=Cold Water Equivalent), steam pressure of 500 psia, and sand face steam quality of 70%. Formation thickness was 36 ft, and no bottom water layer was present. The oil and water production histories shown in Fig. 6.2 are typical of steamfloods, with an initially low production rate, increasing to a high value toward the end of the simulation. The water production rate goes through a peak, and then decreases. Figure 6.3 shows that the WOR (water-oil ratio) peaks at about 18, then steadily declines. This is so because the temperature increase in the producers leads to increasing oil mobility, while water mobility increases much less. This results in a steady increase in the oil-steam ratio, as shown in Fig. 6.4. This trend will continue to a point only. For very large volumes of steam injection, the oil-steam ratio would eventually decrease, since there is not enough mobile oil on one hand, and steam mobility is greatly increased on the other.

Conducting a simulation of this type for very long periods not only requires considerable computer time, but also requires considerable simulation experience. Once the wells get sufficiently hot, the oil mobility increases exponentially, and so does steam

Table 6.2

ABERFELDY STEAMFLOOD RUNS RESULTS SUMMARY

Run No.	Steam Inj. Rate B/D	h _w hoil	Completion	OSR m ³ /m ³	500 days			700 days			Comments
					Cum. WOR	Oil Rec.	Inst. WOR %	Cum. WOR	Oil Rec.	Inst. WOR %	
ABRS1	600	0	1-2	0.097	3.79	1.75	9.32	0.250	1.47	6.25	4.2
ABRS2	600	1.0	1-1	0.028	24.4	0.47	22.70	0.034	20.6	0.81	728.5
ABRS3	600	0	1-2	0.0878	4.80	1.56	10.15	0.189	2.18	4.81	5.2
ABRS4	1200	0	1-2	0.131	1.99	4.71	7.40	0.290	1.18	14.56	3.4
ABRS5	600	0.2	1-1	0.0543	12.1	1.15	16.23	0.113	3.62	3.32	10.7
ABRS6	600	0.1	1-1	0.075	8.34	1.66	12.97	-	-	-	-
ABRS7	600	0.28	1-1	0.0473	13.55	0.988	18.04	0.0745	9.89	2.16	14.6
ABRS8	1200	0	1-2	0.164	1.89	5.74	5.92	0.331	1.12	16.2	2.98
ABRS11	600	0	1-2	0.648	0.73	11.6	0.98	0.883	0.859	22.17	.88
ABRS13	300	0	1-2	-	-	-	-	-	-	-	-
ABRS14	1200	0	1-2	0.196	1.60	7.02	5.09	0.355	1.22	17.8	2.8
ABRS9	600	0.1	-	0.0769	8.31	1.69	12.86	-	-	-	-
ABRS10	1200	0	1-2	0.081	6.0	0.721	10.08	0.186	2.73	2.35	5.5
ABRS15	-	0.2	1-1	0.055	12.3	1.17	16.24	0.0922	6.34	2.58	12.5
ABRS16	-	0.2	1-1	0.376	1.53	8.02	1.90	0.627	0.757	18.0	1.5

Notes: 1. Injection in 2-2, prod. from 1-1 (2-2 is bottom water layer, 1-1 is oil layer).

2. Vertical permeability = 1/5 horizontal permeability.

3. Steam quality in all runs is 70% except in Run ABR3 it is 30%.

STEAMFLOOD RUN ABRS 1, ABERFELDY NO BOTTOM WATER

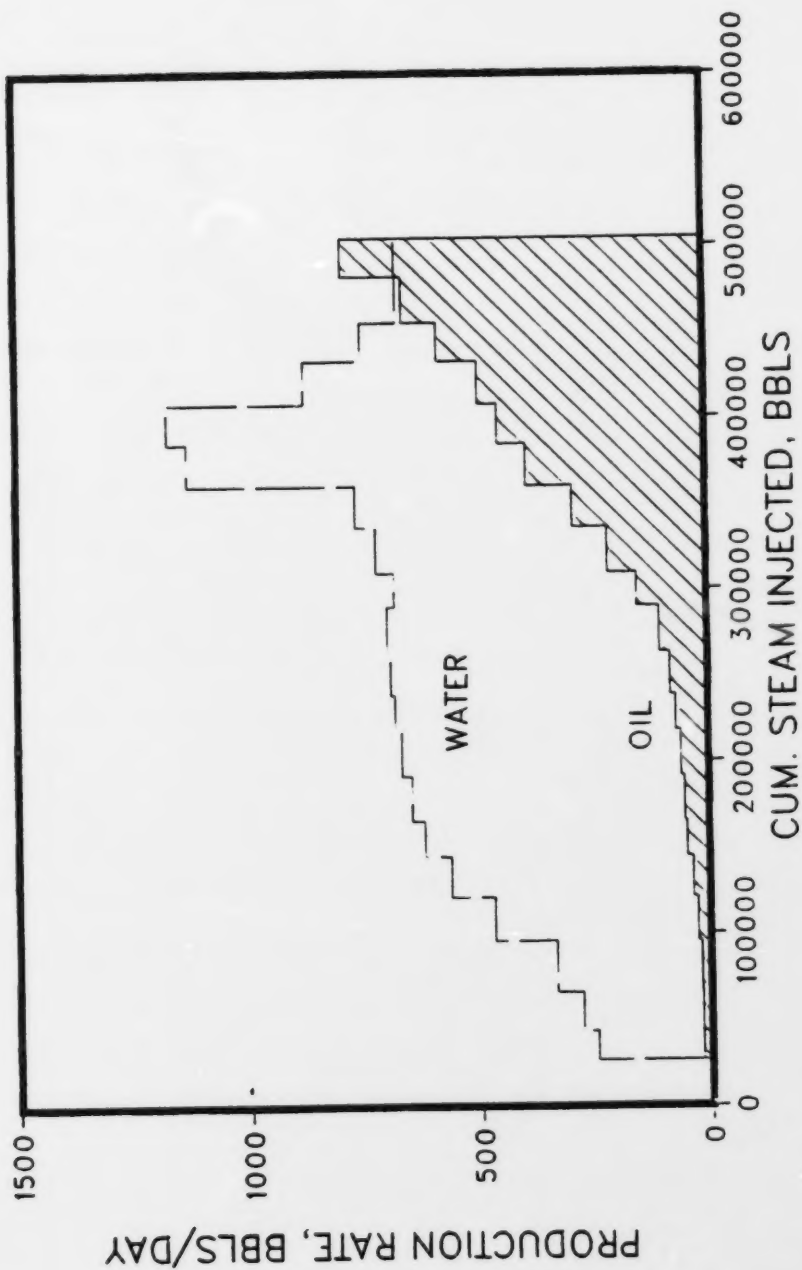


Figure 6.2 Production History of the Aberfeldy Steamflood ABRS1, No Bottom Water

STEAMFLOOD RUN ABRS 1, ABERFELDY
NO BOTTOM WATER

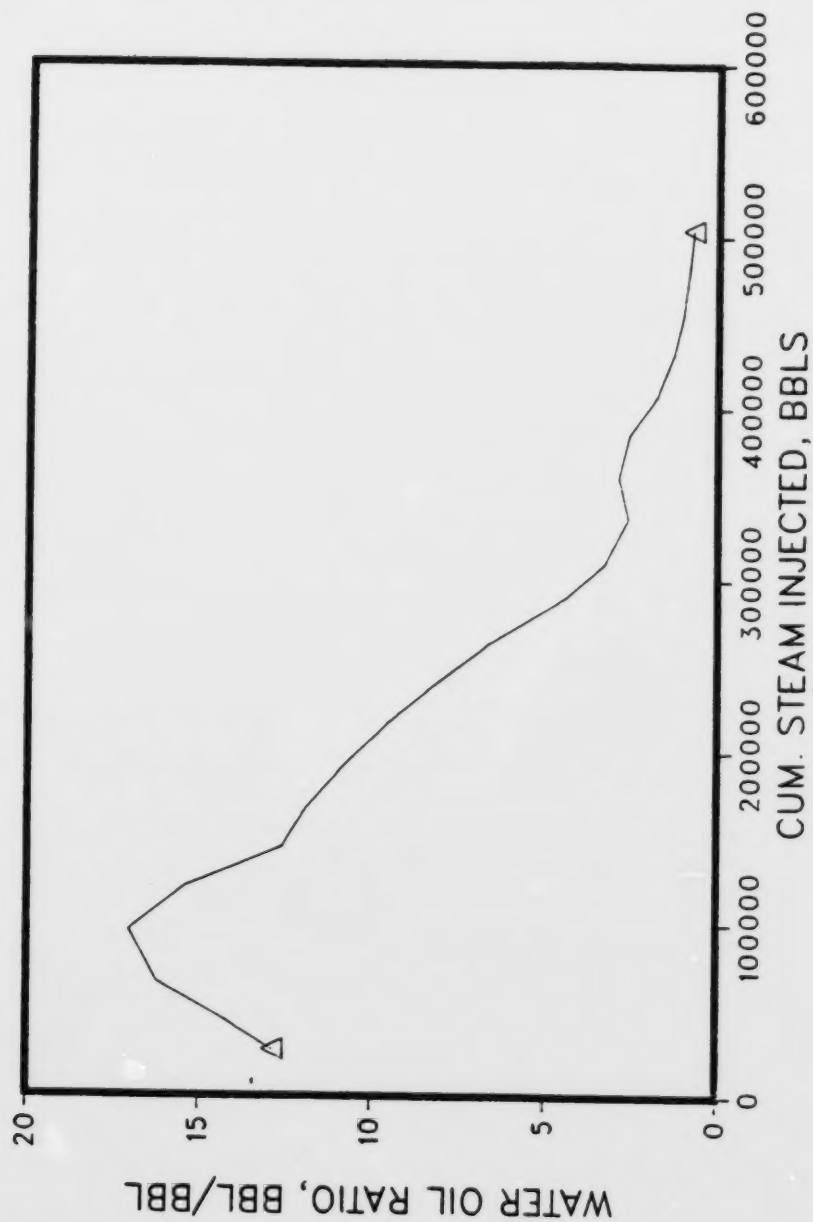


Figure 6.3 Water-Oil Ratio vs. Steam Injected for Aberfeldy Steamflood ABRS1

STEAMFLOOD RUN ABRS 1, ABERFELDY
NO BOTTOM WATER

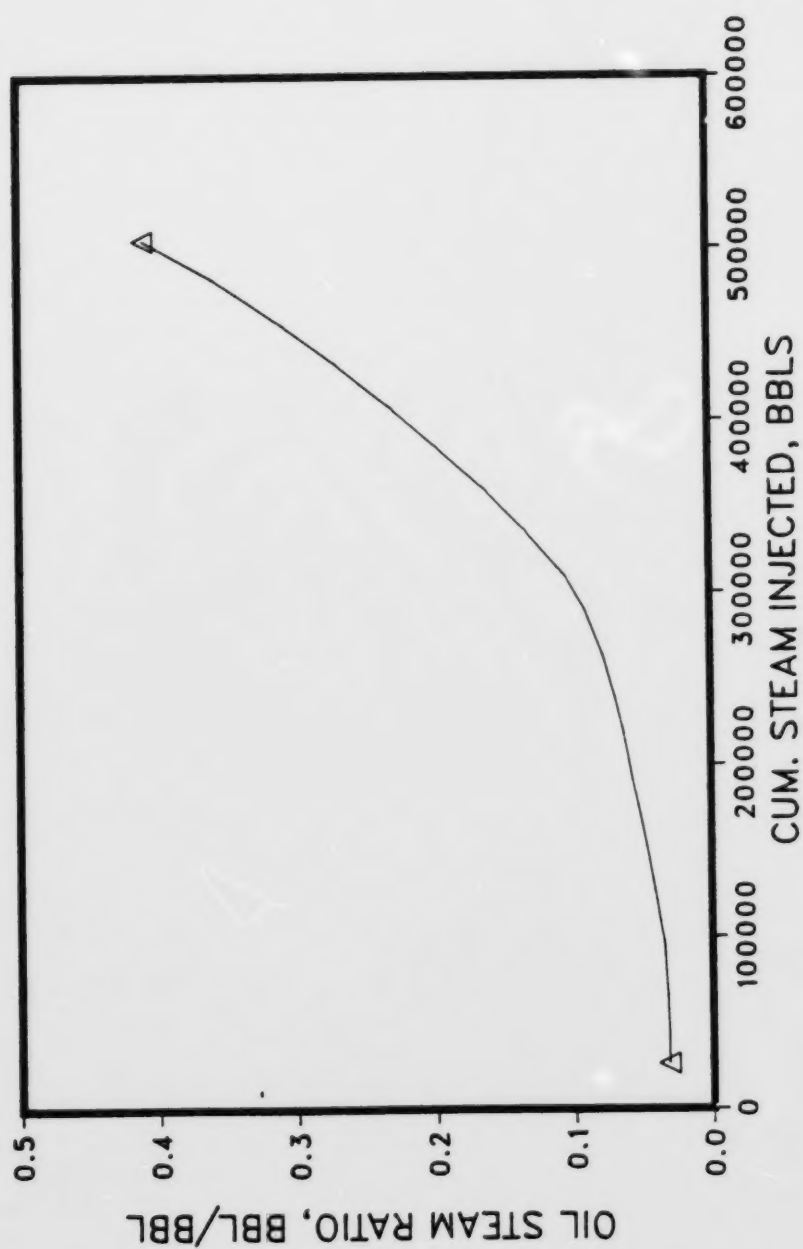


Figure 6.4 Oil-Steam Ratio vs. Steam Injected for Aberfeldy Steamflood ABRS1

injectivity. At such a stage, which can only be identified from previous unsuccessful runs, the steam injection rate and the well production must be reduced (as one does in actual field practice also), to continue to obtain a stable solution. This process needs to be repeated as many times as necessary, as shown by the lack of convergence of the solution, which may be due to excessive physically unrealistic pressure and/or saturation changes.

Temperature, Pressure and Gas Saturation Behaviour in a Multilayer Steamflood

In a steamflood, the formation temperatures, pressures, and saturations vary in a complex manner, depending on the formation characteristics, especially permeability, oil viscosity, and steam injection interval, as well as rate, pressure, and quality. The effects of these variables can be seen from the individual simulation histories. As an example, a detailed analysis is given of Run ABR510. Figures 6.5 to 6.7 give the oil/water production data, water-oil ratio, and oil-steam ratio, respectively, while Figs. 6.8 through 6.10 show the injection well block pressure, temperature, and gas saturation histories, respectively, versus time. The injection was completed in both layers representing the formation. There was no bottom water in this run.

Initially the reservoir oil has a very low mobility (viscosity 1200cp), and as a result, the steam pressure in the injection block is high. As steam injection proceeds, the steam pressure increases rapidly (Fig. 6.8), and reaches a peak value of about 450 psi at about 400 days. The oil and water production curves (Fig. 6.5) up to this time show that the oil rate is very small, and the water rate is building up, both starting from nearly zero (because of initially immobile water, and very low oil mobility). The temperature curves show (Fig. 6.9) that during this period, the bottom layer temperature was somewhat higher than that of the top layer. This behaviour was evident in many of the runs conducted in the case of a uniform formation, where the perforations were allowed to take steam according to the steam pressure and the prevailing flow resistance. It is partly explained by the fact that, initially, the injected steam condenses, so that much hot water enters the formation. The

STEAMFLOOD RUN ABRs 10, ABERFELDY NO BOTTOM WATER

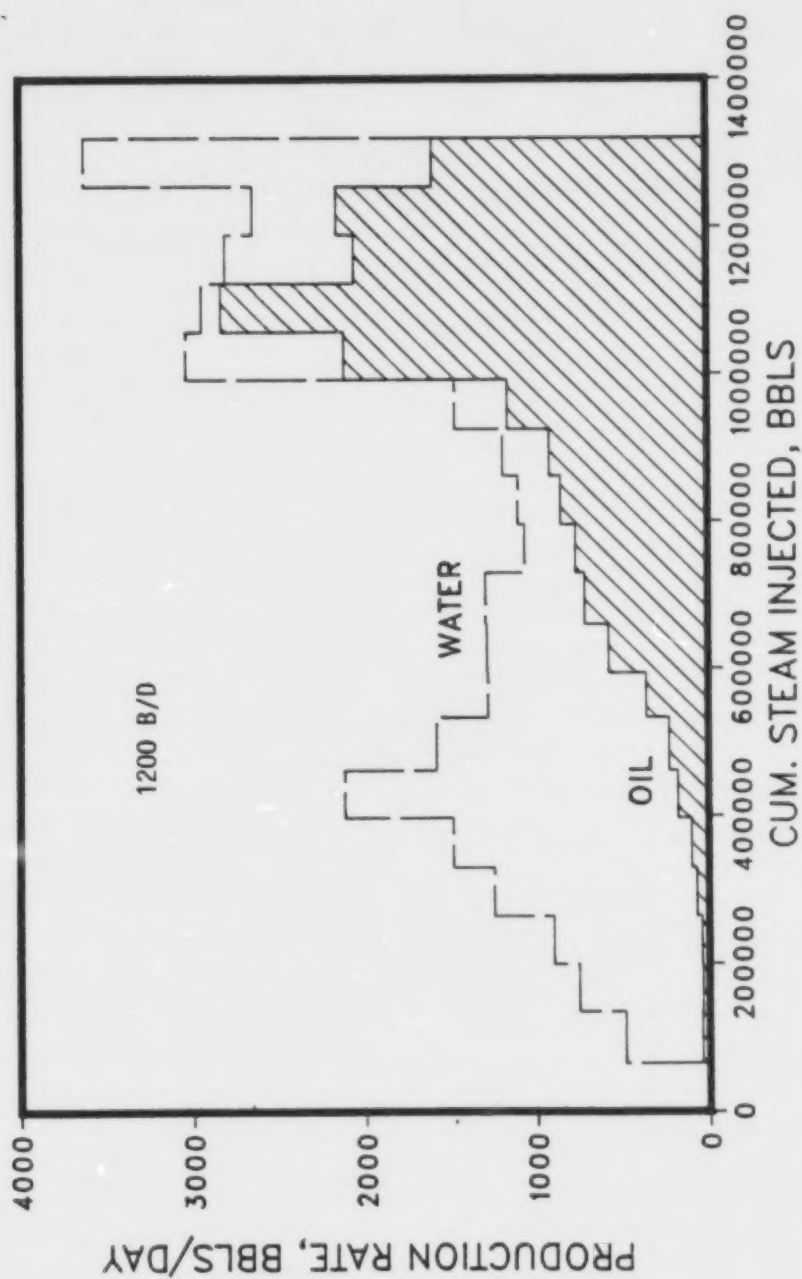


Figure 6.5 Production History of the Aberfeldy Steamflood ABRs 10, No Bottom Water

STEAMFLOOD RUN ABRS 10, ABERFELDY
NO BOTTOM WATER

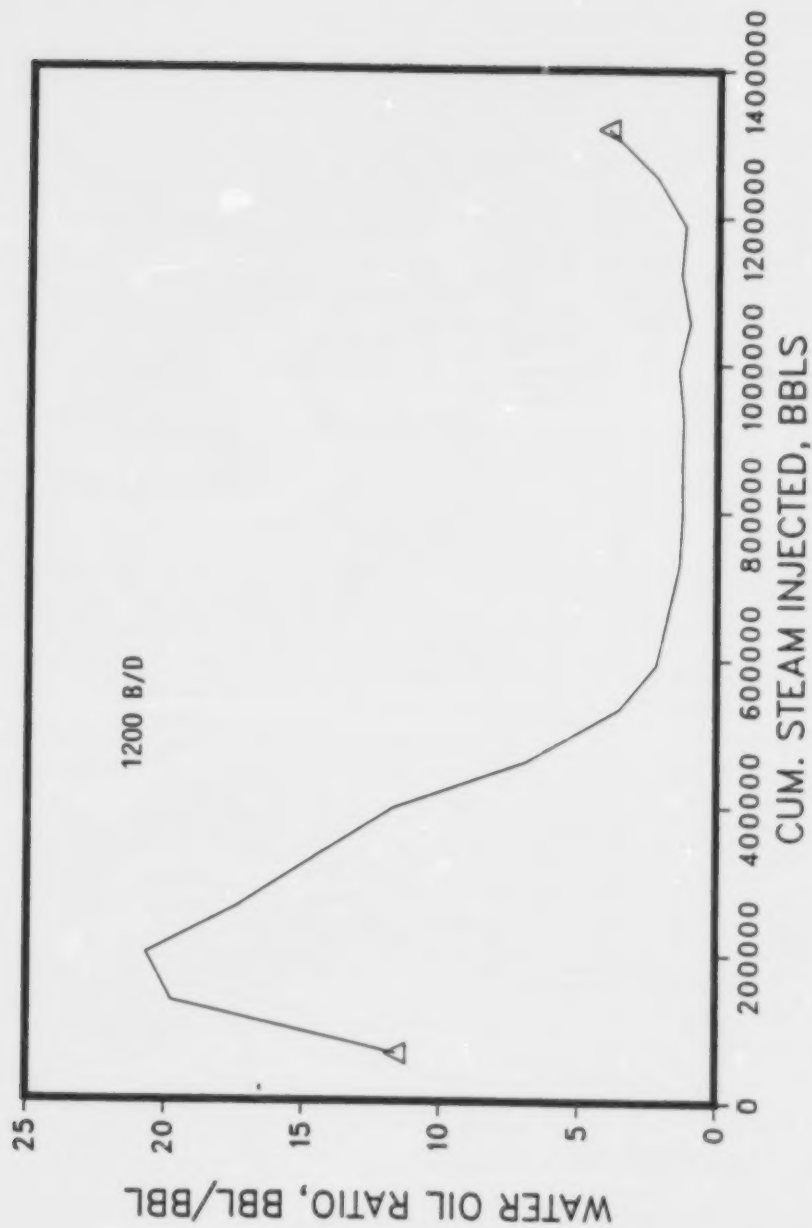


Figure 6.6 Water-Oil Ratio vs. Steam Injected for Aberfeldy Steamflood ABRS10

STEAMFLOOD RUN ABRS 10, ABERFELDY
NO BOTTOM WATER

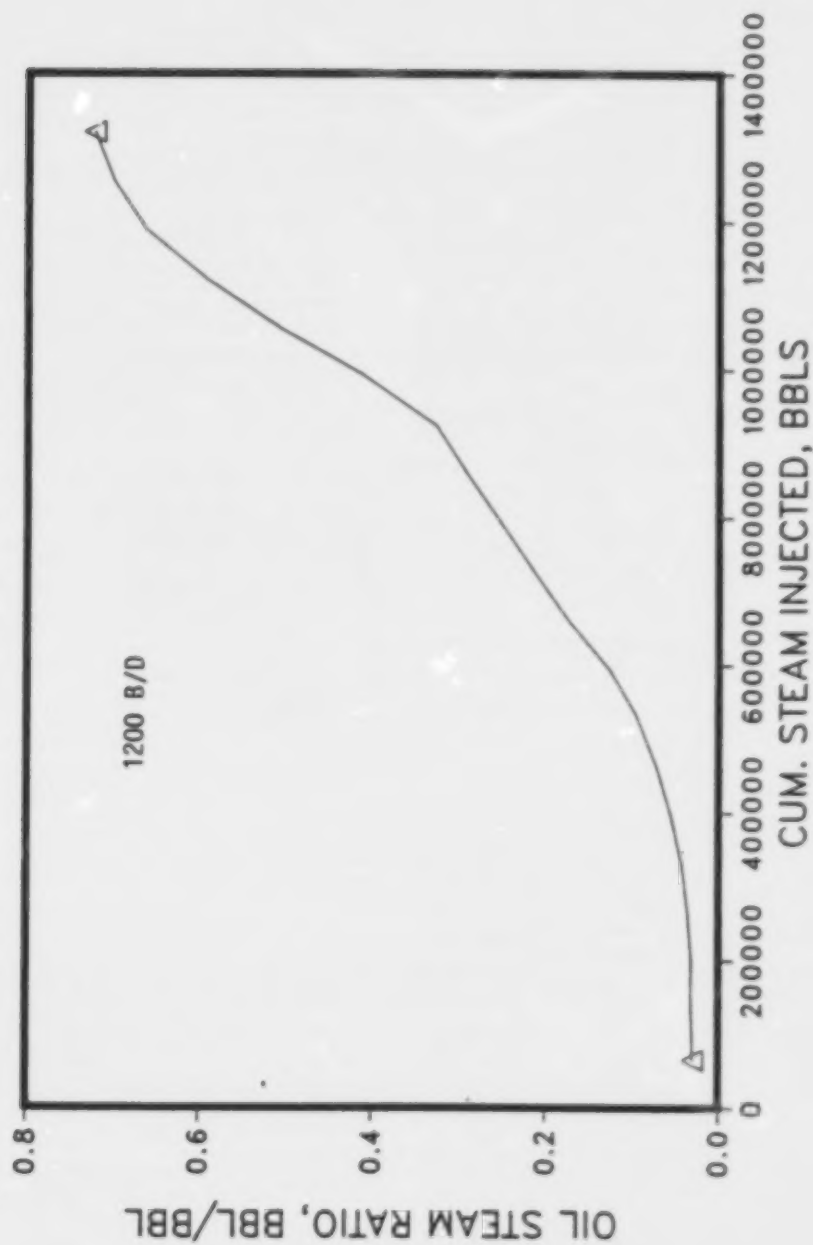


Figure 6.7 Oil-Steam Ratio vs. Steam Injected for Aberfeldy Steamflood ABRS10

STEAMFLOOD RUN ABRs 10, ABERFELDY
NO BOTTOM WATER

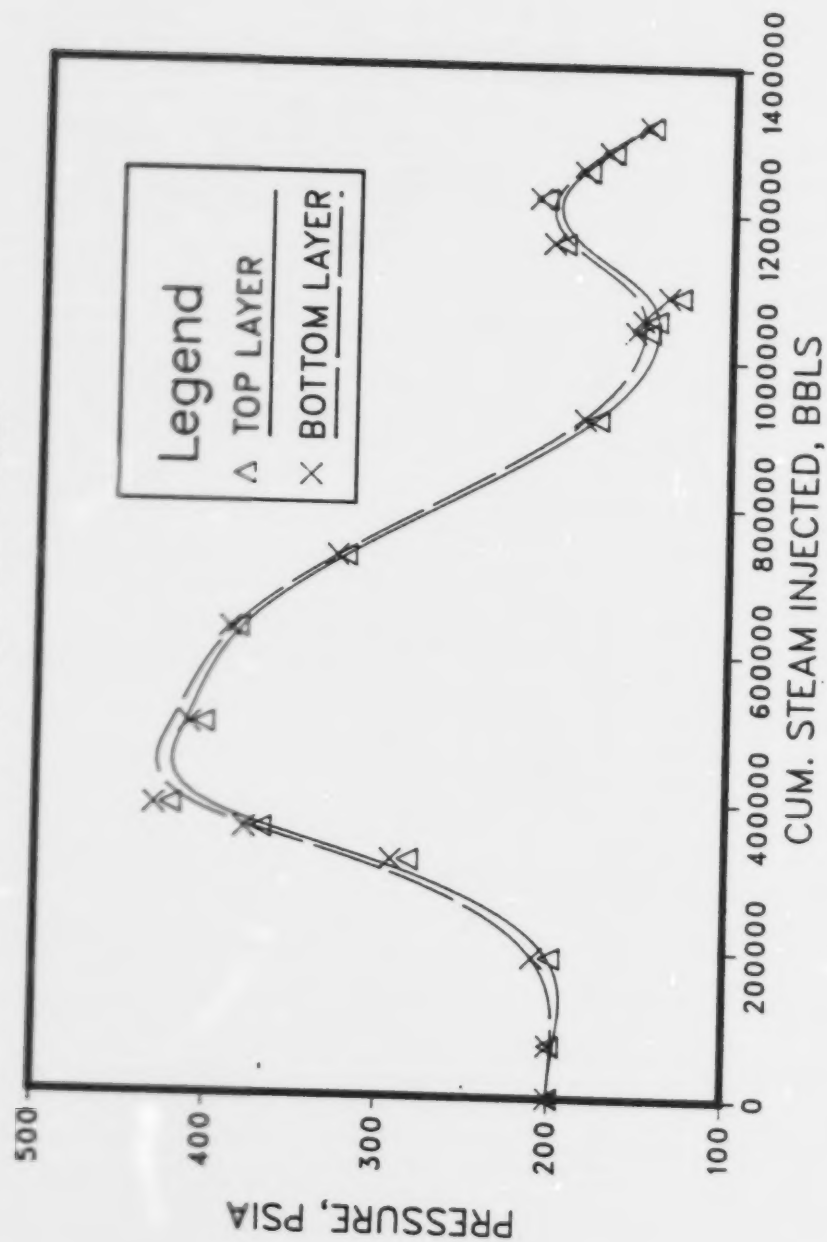


Figure 6.8 Pressure Variation in the Injection Well Block, Steamflood Run ABRs 10

STEAMFLOOD RUN ABRS 10, ABERFELDY
NO BOTTOM WATER

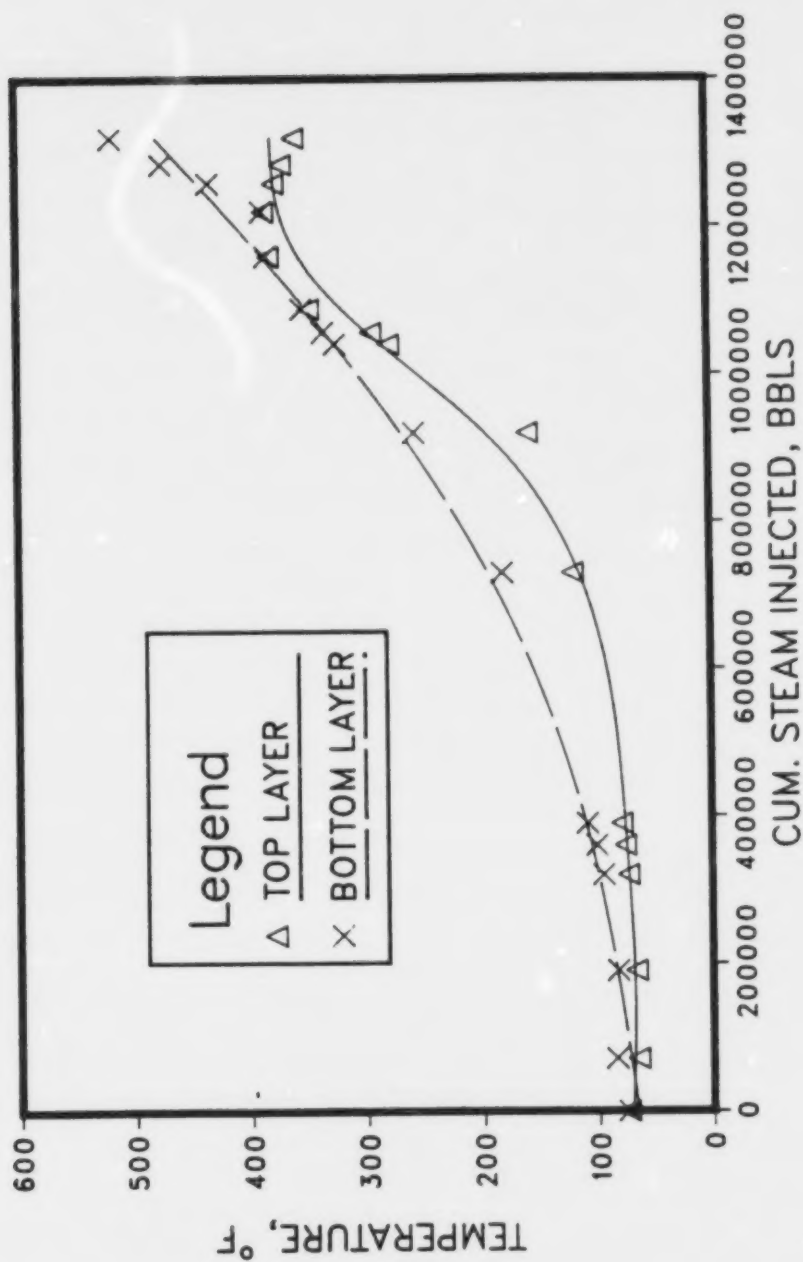


Figure 6.9 Temperature Variation in the Injection Well Block, Steamflood Run ABRS10

STEAMFLOOD RUN ABRS 10, ABERFELDY NO BOTTOM WATER

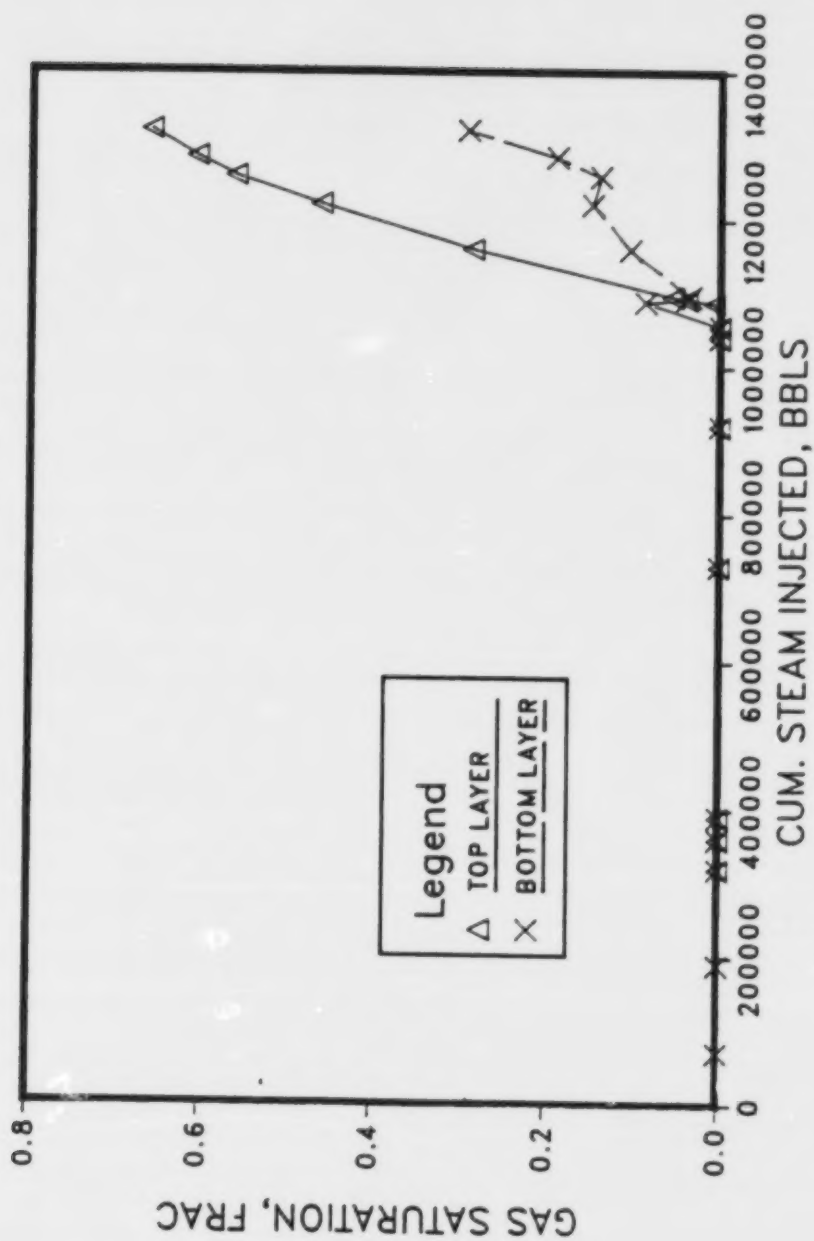


Figure 6.10 Gas Saturation Variation in the Injection Well Block, Steamflood Run ABRS10

segregated hot water tends to create a higher permeability to water in the lower part of the formation, which further helps steam inflow into this part. Initial segregation of steam will occur in the case of (i) low viscosity oils, (ii) an initial gas saturation, or (iii) completion in the upper part of the formation only. Even in the case of high viscosity oils, steam segregation would tend to occur at long times. As a result of low oil mobility, the water-oil ratio increases rapidly during the initial period (Fig. 6.6).

As steam injection continues, the hot condensate arrives at the producers, causing an increase in the oil mobility. Consequently, the oil rate increases rapidly (Fig. 6.5), together with the water rate. The injection block pressure drops during this period also (Fig. 6.8), to a value of about 200 psi. At this point, the temperatures in the upper and lower parts of the formation are nearly equal (Fig. 6.9 at 1.1 MMBbls steam injected). The water-oil ratio declines during this period, and tends to level out at a value of about 2, compared to the peak value of 20. At about this point, the gas saturation, which was higher initially in the lower layer, now starts to increase in the upper part (Fig. 6.10). As a result, more steam is diverted to the upper part. The injection block pressure rises somewhat due to an increase in flow resistance resulting from gas saturation buildup (Fig. 6.9, temperatures beyond 1.2 MMBbls steam injected), coupled with the decreasing oil saturation, both lowering the oil mobility. Thus the small pressure peak seen in Fig. 6.8 is the result of the above mentioned complex interactions.

In the last part of the run, most of the steam continues to flow into the upper part of the formation (gas saturation 56% vs. 14% in the lower part), the temperature of the lower part continues to increase. The pressure declines rapidly after the second peak (Fig. 6.8), because of steam breakthrough, resulting in a marked decline in the formation resistance. The oil production rate declines during this period (Fig. 6.5), because there is less oil left in the formation. As a result, the water-oil ratio increases (Fig. 6.6) to 4, but not much more, because the water saturation, hence permeability, is also low.

The cumulative oil-steam ratio curve shows a behaviour consistent with the above discussion. Initially, the increase in the oil-steam ratio is slow, since the steam injection rate is constant, but the oil production rate is low. Later, as the oil is mobilized, the oil-steam ratio increases rapidly. During the last stage of steam injection, the oil-steam ratio tends to level off.

It should be noted that if steam injection is continued beyond the stage at which the run is terminated, steam flow rate increases very rapidly, until steam (gas) is the only flowing phase. In field practice, after steam breakthrough the steam injection rate is greatly turned down. From this point on there is only a decrease in the oil-steam ratio, because no more oil is produced. From a computational point of view, the steam injection rate has to be cut down also, but the solution convergence rate still slows down greatly due to the high gas flow rate.

Bottom Water Steamfloods for Aberfeldy:

Effect of Bottom Water Thickness Table 6.2 (p.101) summarizes selected steamfloods carried out for the Aberfeldy formation. The floods with bottom water present are indicated by a nonzero ratio h_w/h_{oil} , i.e. the ratio of water layer to the oil layer thickness. Figure 6.11 shows plots of oil-steam ratio versus h_w/h_{oil} for Aberfeldy and M-6 steamfloods. In the runs indicated, steam was injected into the oil zone only, with the producers completed in the oil zone also. It is clear that the oil-steam ratio declines steeply with an increase in the h_w/h_{oil} ratio. The decline is much smaller for M-6. It is also seen that the oil-steam ratio reaches a low rather early for the high h_w/h_{oil} ratios, whereas for lower ratios, there is considerable difference between the 500 and 700 day oil-steam ratio curves. This implies that in the thicker water zones, steam penetrates the bottom water zone early, and from then onward, there is little improvement in the oil displacement efficiency.

Figure 6.11 also shows the oil recovery curve for the 700-day period. The recovery drops rapidly with an increase in h_w/h_{oil} ratio, based upon the same reasons as noted for

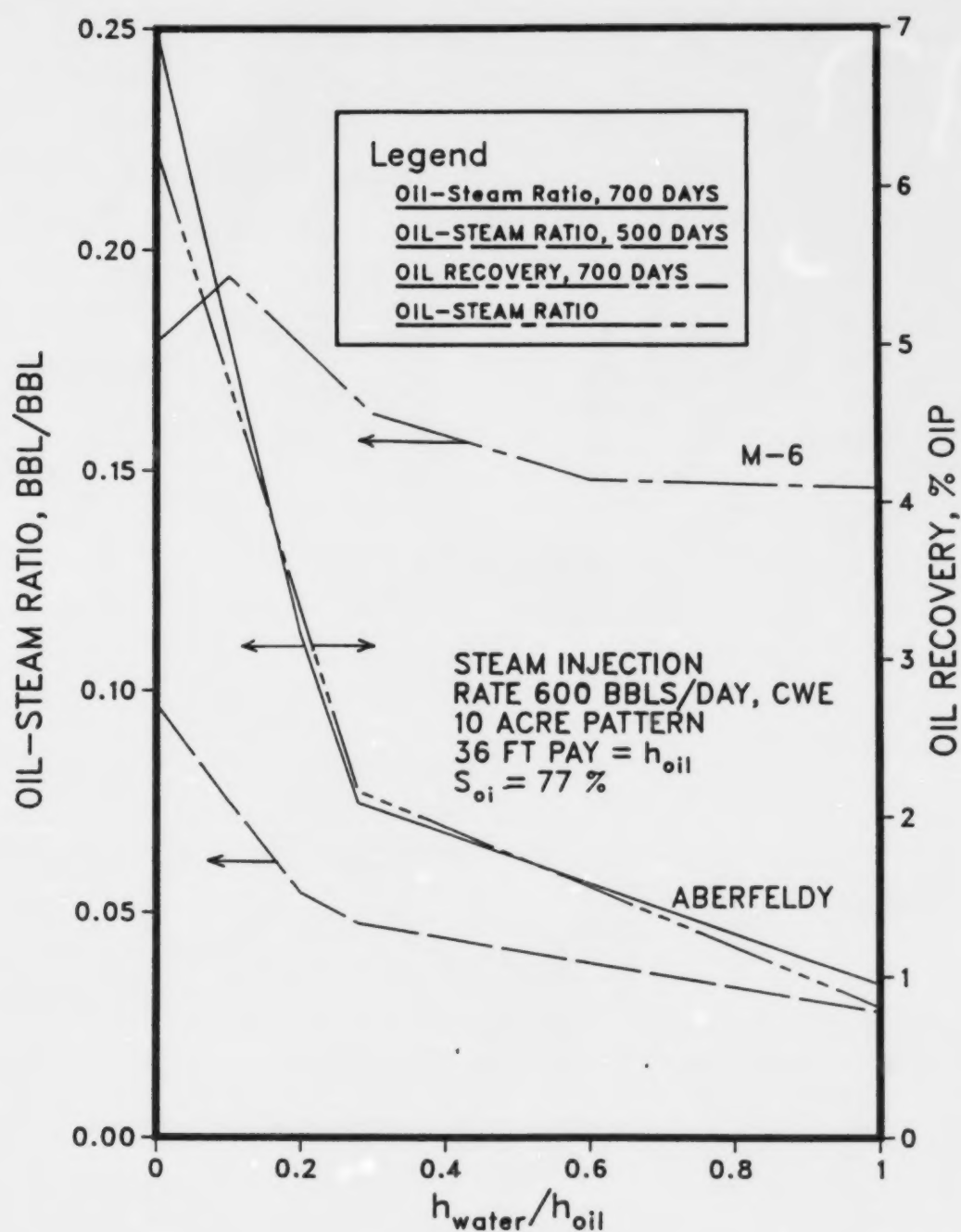


Figure 6.11 Variation of Oil-Steam Ratio and Recovery With Water-Oil Zone Thickness Ratio.

the oil-steam ratio. The cumulative WOR for $h_w/h_{oil} = 1$ (ABRS2) was 20.6, compared to 1.47, when no bottom water was present.

Figures 6.12 through 6.23 show the oil and water production history, water-oil ratio, and oil-steam ratio plots for the bottom water runs ABRS2, ABRS6, ABRS5, and ABRS7, with $h_w/h_o = 1, 0.1, 0.2$, and 0.28 , respectively. The trends in all four cases are similar, but the scales are different. In other words, the steam injection process works the same way whether bottom water is present or not. But when bottom water is present, much less steam flows in the oil zone than that in the absence of bottom water. In particular, the slow drop in WOR in Run ABRS2 (Fig. 6.13) is noticeable due to the fact that, even though the oil is mobilized (causing a drop in WOR), considerable amounts of water continue to flow from the water zone into the producers.

Effect of Bottom Water Oil Saturation

In all of the runs conducted, it was assumed that the bottom water contains residual oil only, so that water is the only mobile phase. If a higher oil saturation is assumed, or if it is assumed that the residual oil saturation decreases with an increase in temperature, a small amount of oil will be produced from the "water" zone. An interesting example of this type is the Peace River project, where the bottom "water" layer has an oil saturation of 55-60%, so that steam injection into the bottom water produces a considerable volume of oil. The oil formations in the Cold Lake area often have oil saturations in the same range. However, whereas the water in Peace River is mobile, it is often immobile in Cold Lake because of the fine grained sand and clays present.

One run, ABRS2A, was carried out to determine the effect of bottom water oil saturation on recovery. The data used were the same as for Run ABRS2, except in this case, the oil saturation in the water layer was increased to 50% to simulate a transition zone. Figure 6.24 shows plots of oil and water production rates versus cumulative steam injection. Figure 6.25 shows a similar plot for the oil-steam ratio. (Results are tabulated in

STEAMFLOOD RUN ABRs 2, ABERFELDY BOTTOM WATER

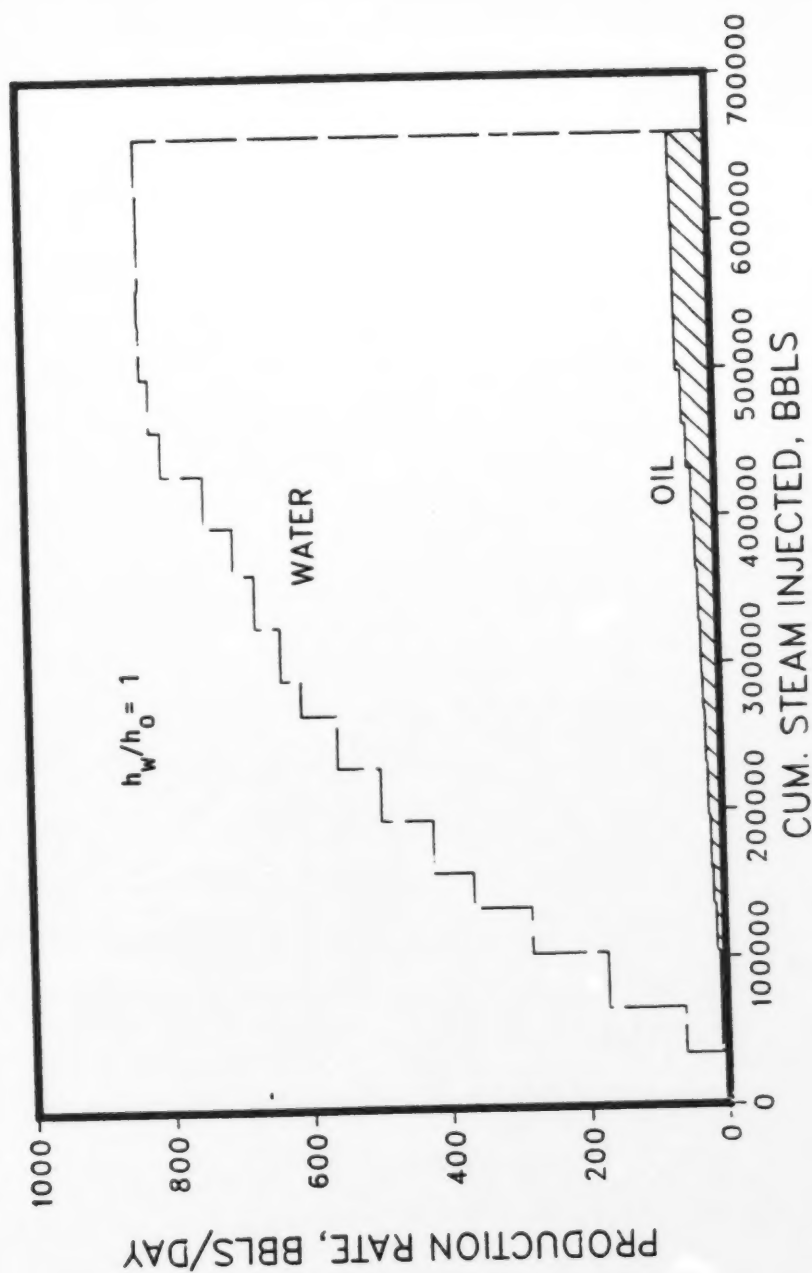


Figure 6.12 Production History of the Aberfeldy Steamflood ABRs2, Bottom Water

STEAMFLOOD RUN ABRS 2, ABERFELDY BOTTOM WATER

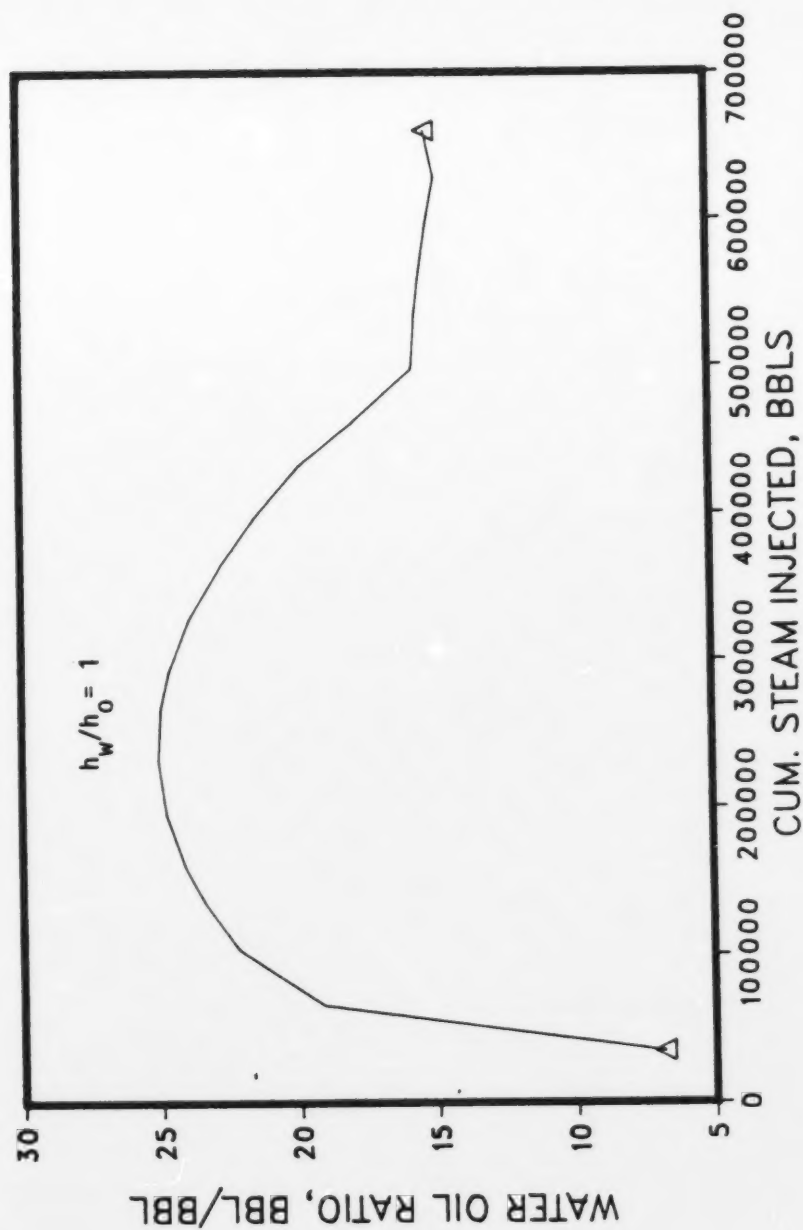


Figure 6.13 Water-Oil Ratio vs. Steam Injected for Aberfeldy Steamflood ABRS2

STEAMFLOOD RUN ABRS 2, ABERFELDY
BOTTOM WATER

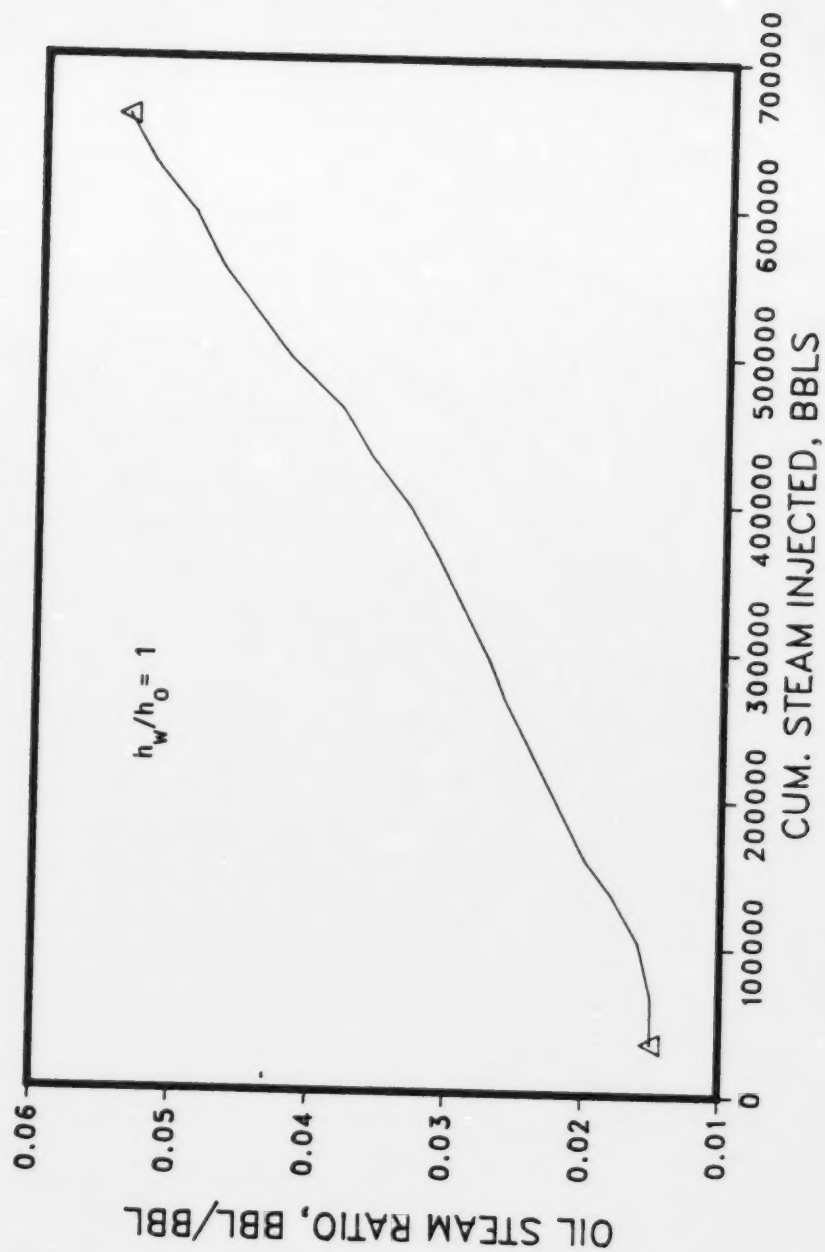


Figure 6.14 Oil-Steam Ratio vs. Steam Injected for Aberfeldy Steamflood ABRS2

STEAMFLOOD RUN ABRS 6, ABERFELDY BOTTOM WATER

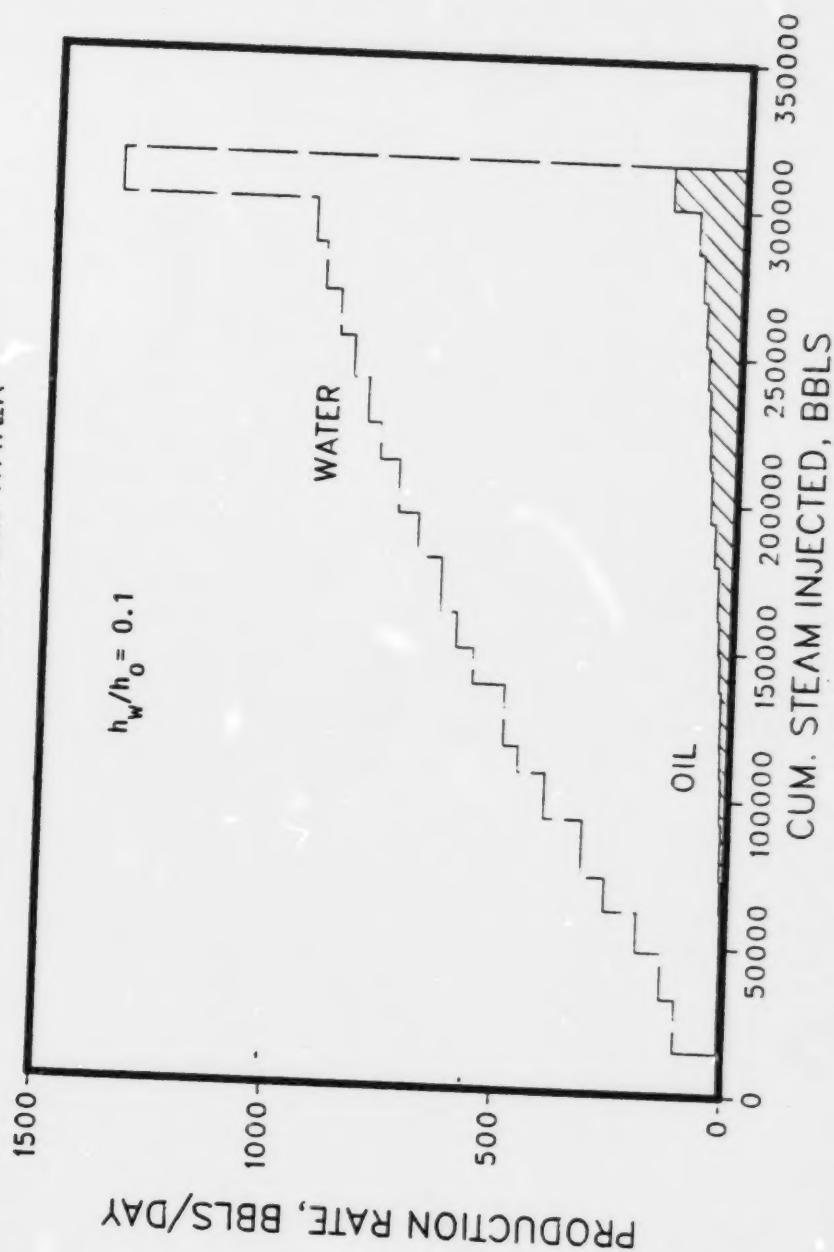


Figure 6.15 Production History of the Aberfeldy Steamflood ABRS6, Bottom Water

STEAMFLOOD RUN ABRs 6, ABERFELDY
BOTTOM WATER

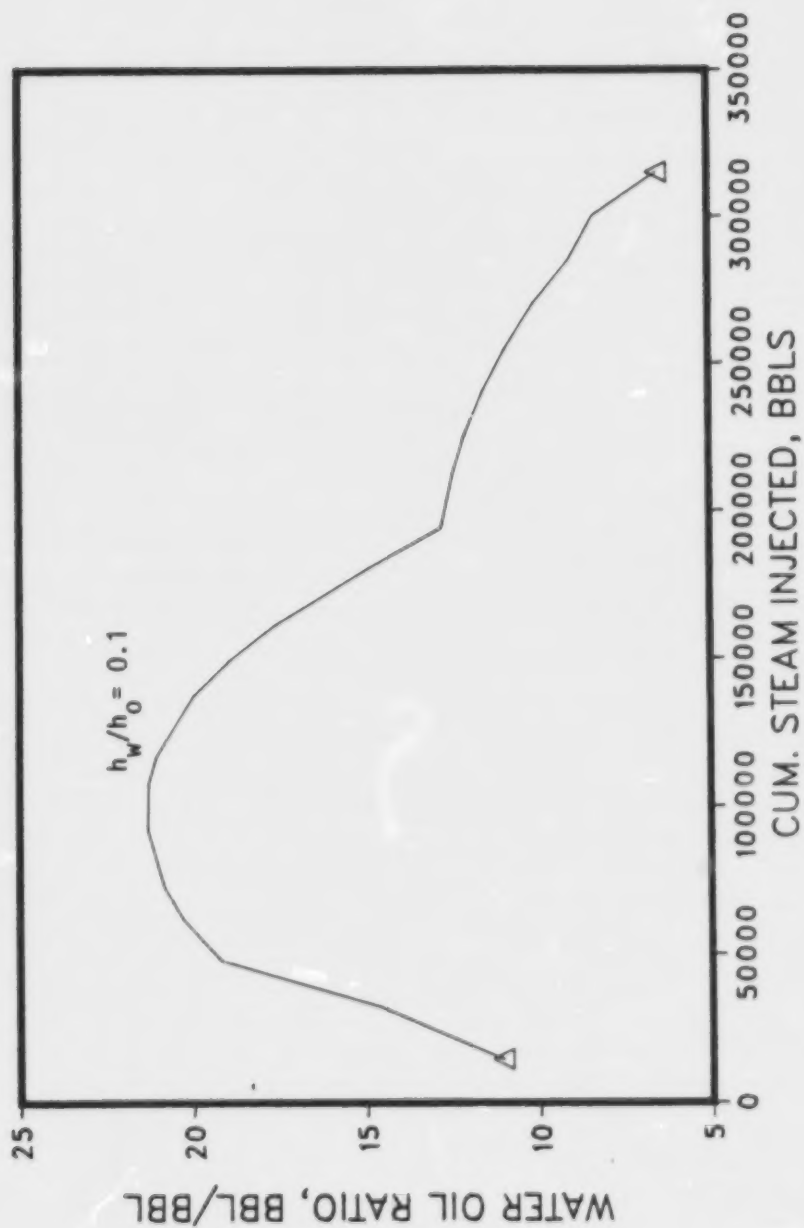


Figure 6.16 Water-Oil Ratio vs. Steam Injected for Aberfeldy Steamflood ABRs 6

STEAMFLOOD RUN ABRS 6, ABERFELDY BOTTOM WATER

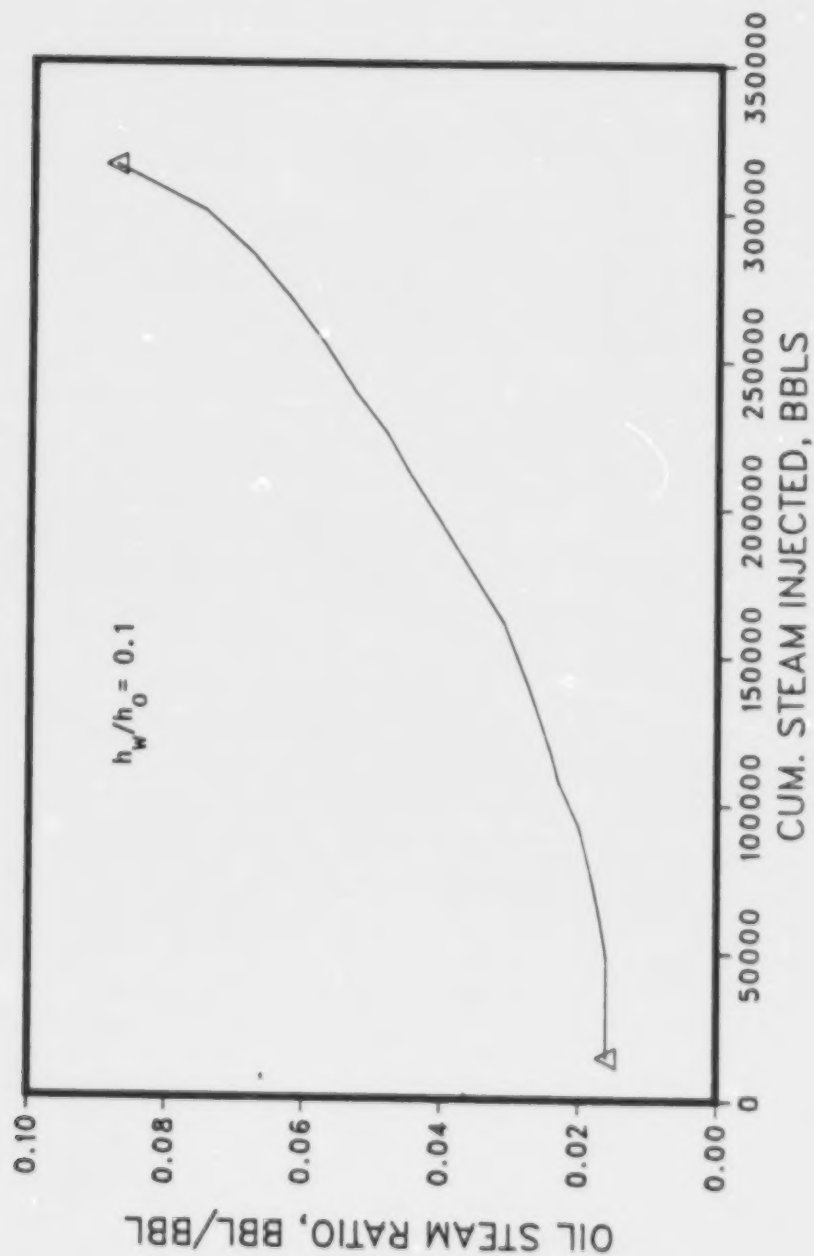


Figure 6.17 Oil-Steam Ratio vs. Steam Injected for Aberfeldy Steamflood ABRS6

STEAMFLOOD RUN ABR5 5, ABERFELDY
BOTTOM WATER

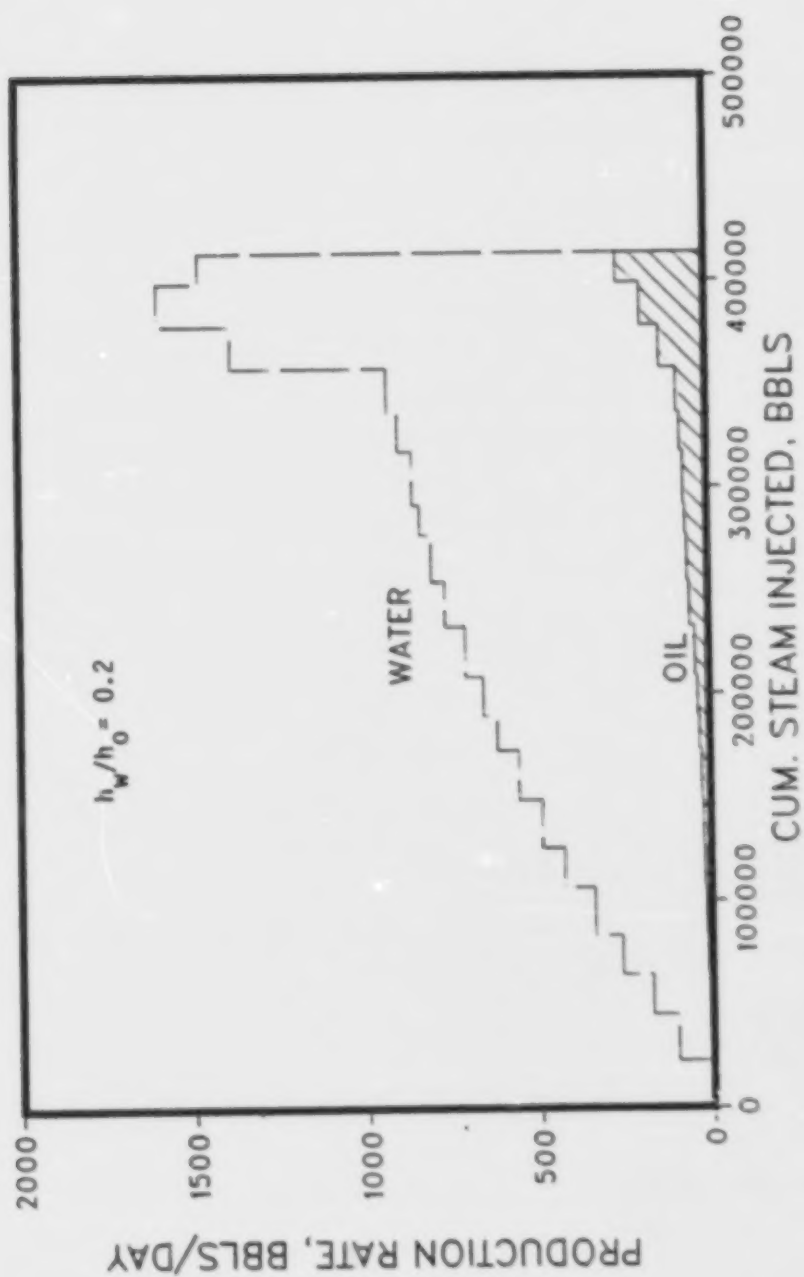


Figure 6.18 Production History of the Aberfeldy Steamflood ABR55, Bottom Water

STEAMFLOOD RUN ABRS 5, ABERFELDY
BOTTOM WATER

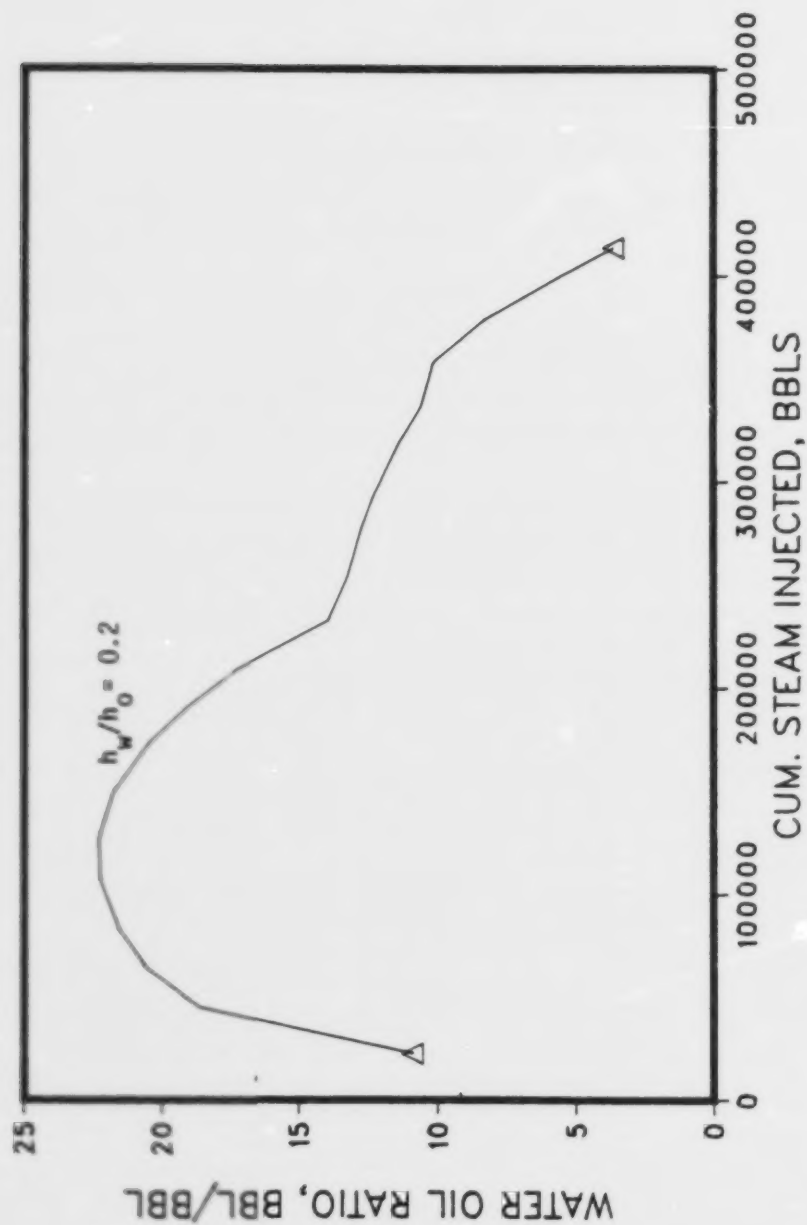


Figure 6.19 Water-Oil Ratio vs. Steam Injected for Aberfeldy Steamflood ABRS5

STEAMFLOOD RUN ABR5 5, ABERFELDY
BOTTOM WATER

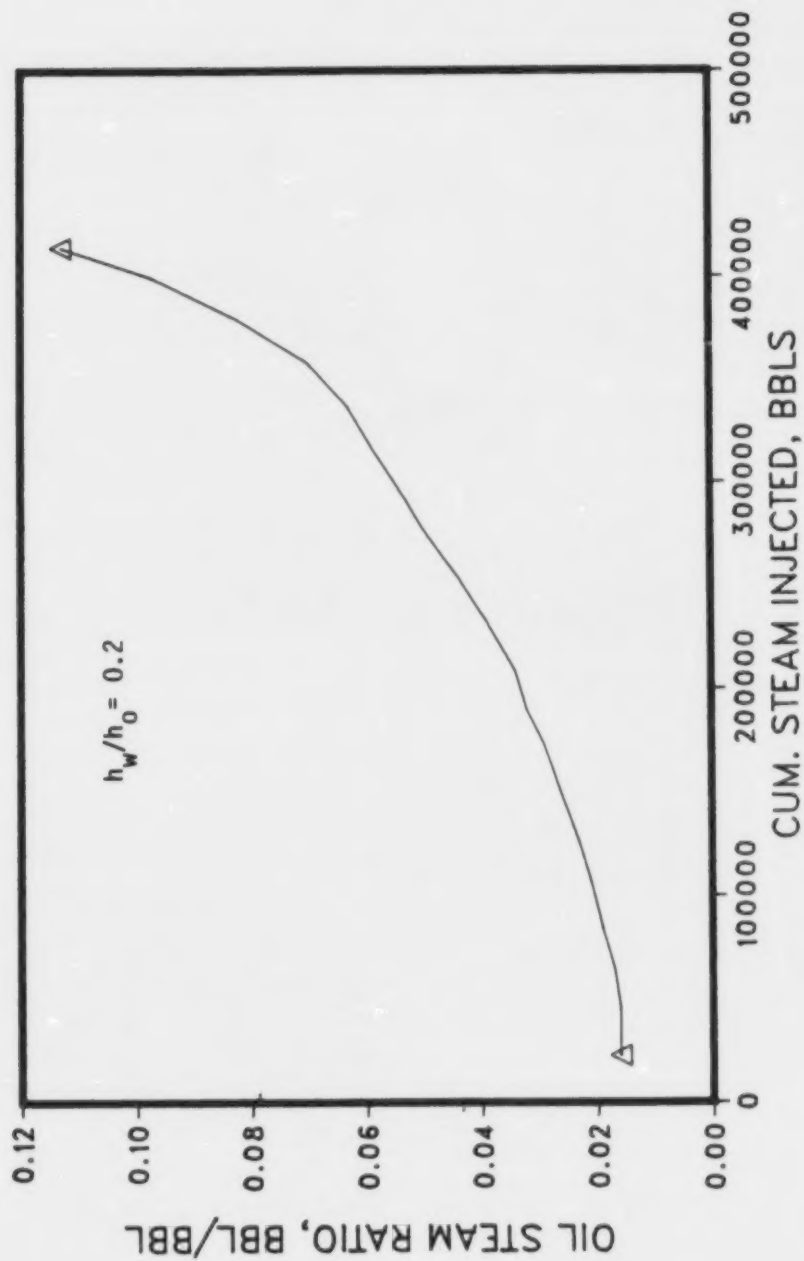


Figure 6.20 Oil-Steam Ratio vs. Steam Injected for Aberfeldy Steamflood ABR55

STEAMFLOOD RUN ABRS 7, ABERFELDY
NO BOTTOM WATER

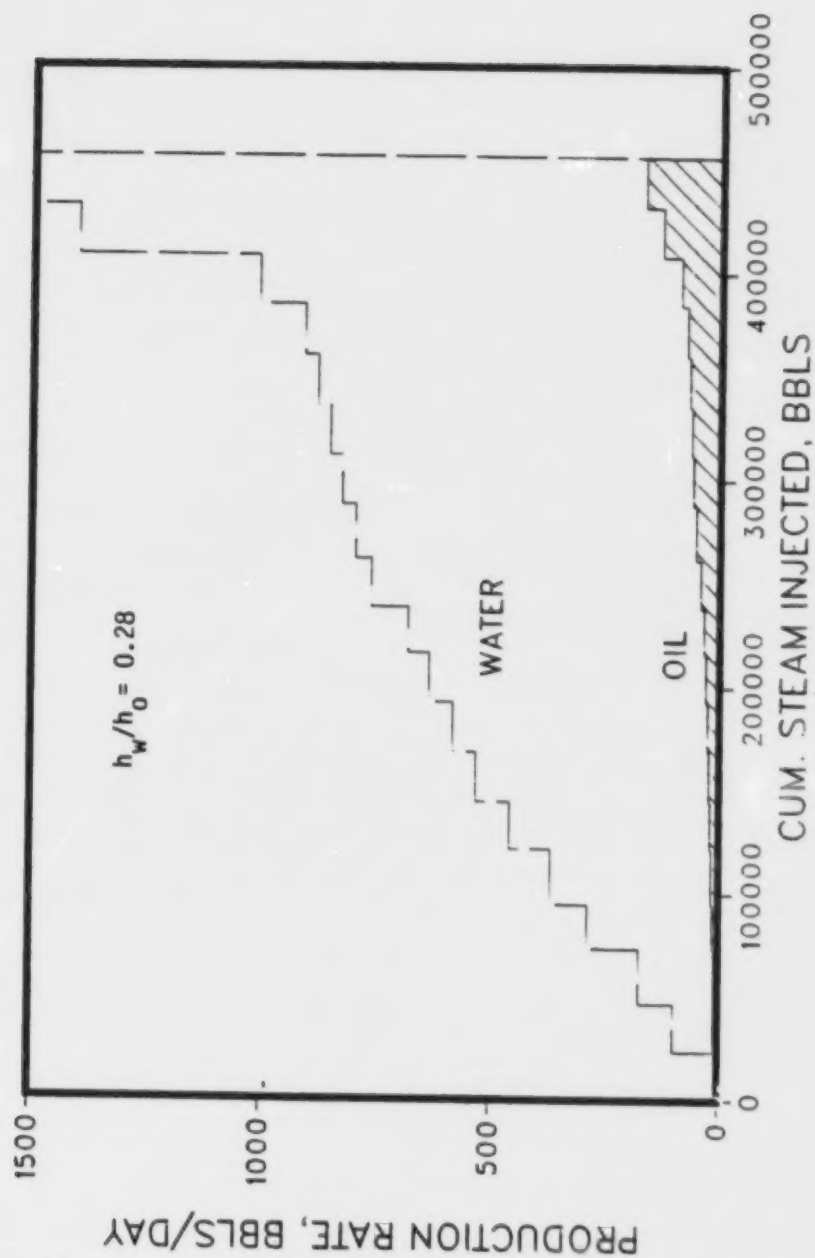


Figure 6.21 Production History of the Aberfeldy Steamflood ABRS7, Bottom Water

STEAMFLOOD RUN ABRs 7, ABERFELDY
NO BOTTOM WATER

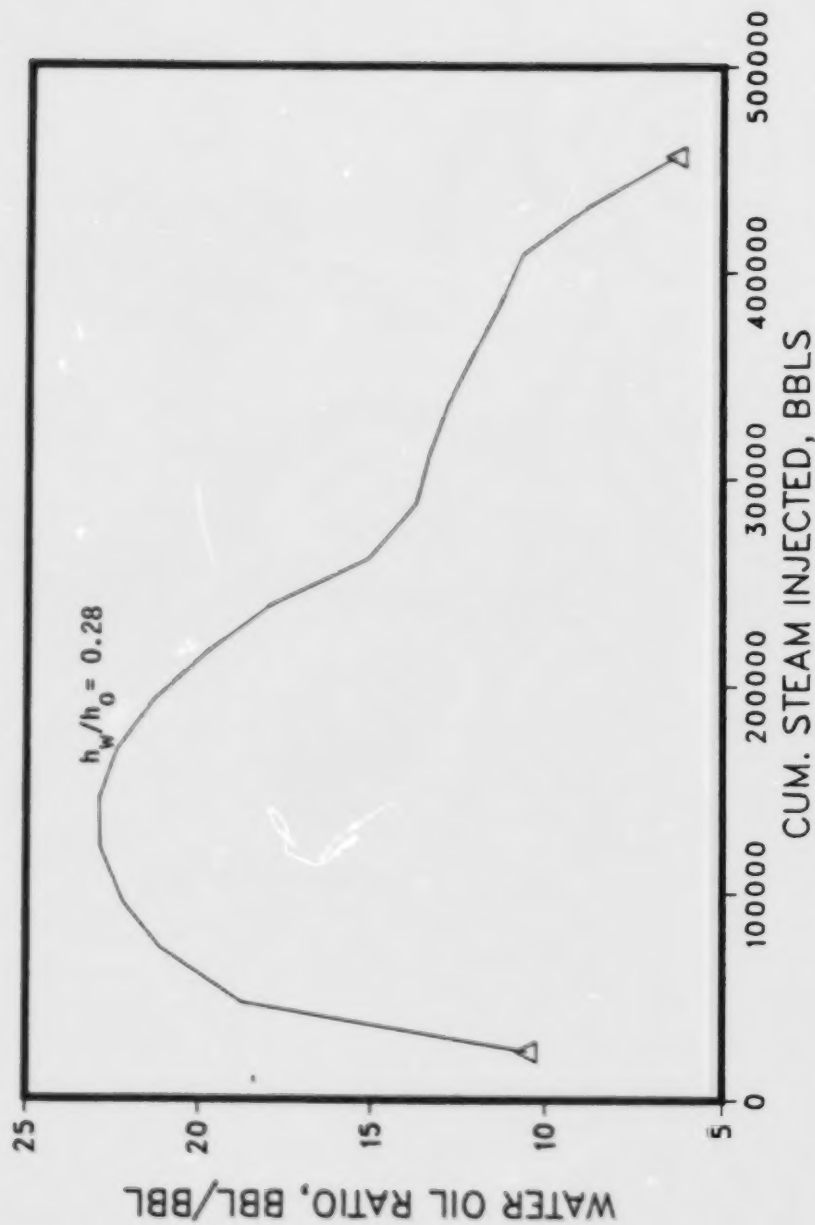


Figure 6.22 Water-Oil Ratio vs. Steam Injected for Aberfeldy Steamflood ABRs 7

STEAMFLOOD RUN ABRs 7, ABERFELDY
NO BOTTOM WATER

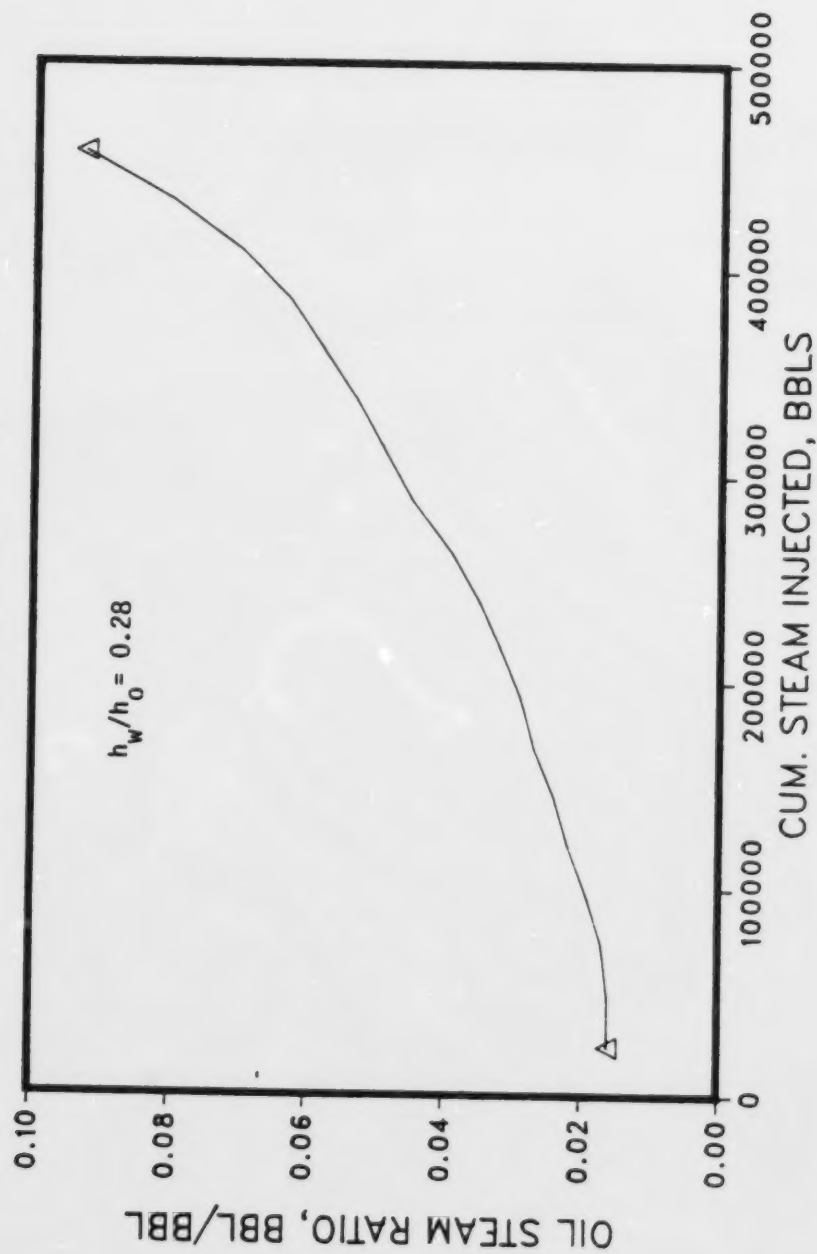


Figure 6.23 Oil-Steam Ratio vs. Steam Injected for Aberfeldy Steamflood ABRs 7

BOTTOM WATER, 36FT/36FT, STEAMFLOOD; ABERFELDY RUN ABR2A
 INJ. OVER ENTIRE INTERVAL; MOBILE OIL (50%) IN BW ZONE
 INJ. RATE 600 BBL/DAY

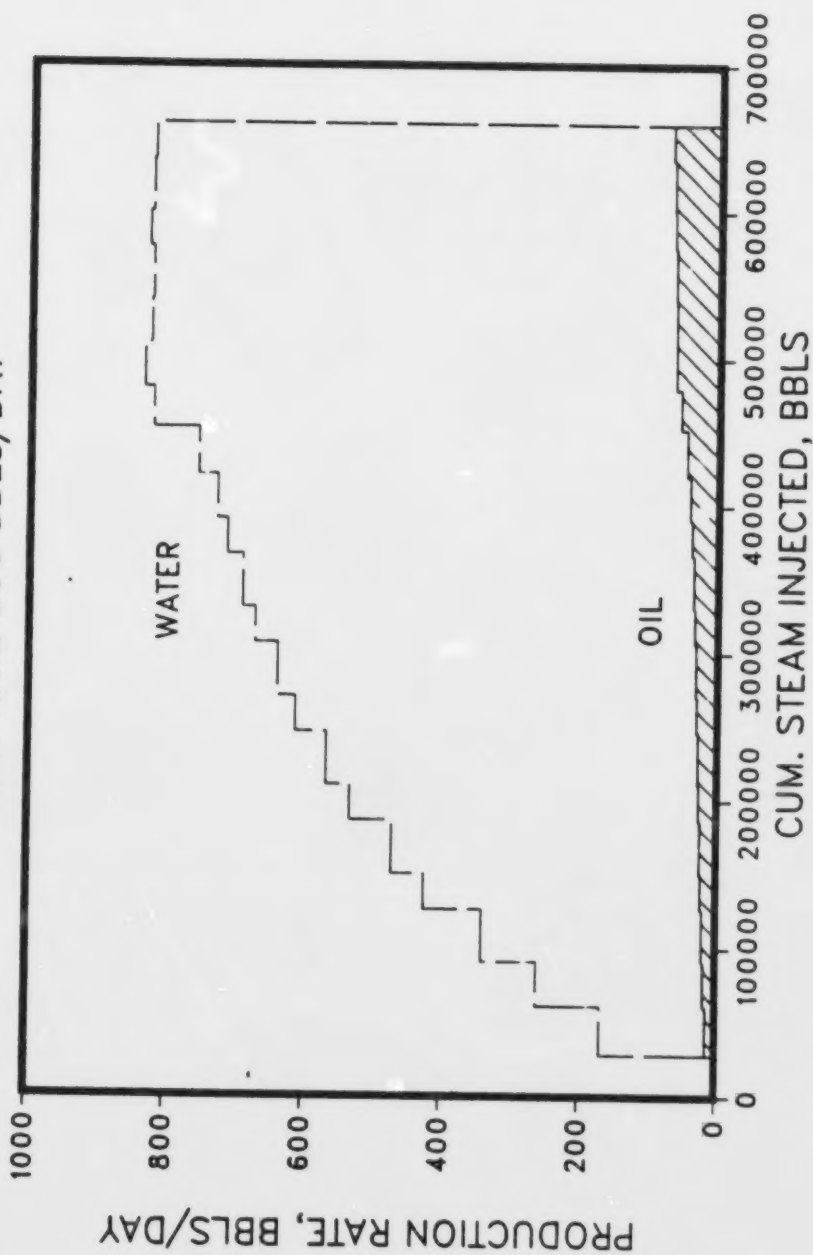


Figure 6.24 Production History of the Aberfeldy Steamflood ABR2A, Bottom Water

BOTTOM WATER, 36FT/36FT, STEAMFLOOD; ABEFRELDY RUN ABR2A
INJ. OVER ENTIRE INTERVAL; MOBILE OIL (50%) IN BW ZONE
INJ. RATE 600 BBL/DAY

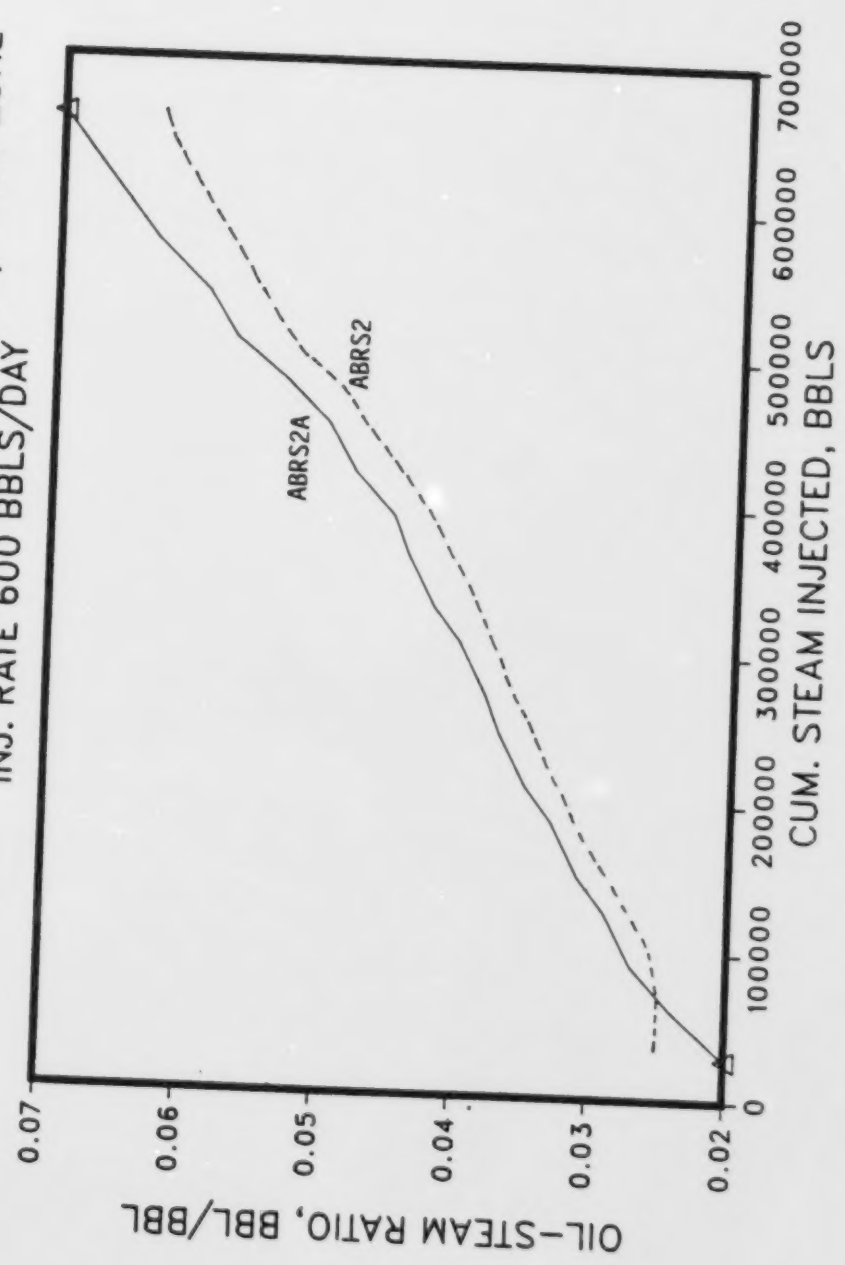


Figure 6.25 Oil-Steam Ratio vs. Steam Injected for Aberfeldy Steamflood ABR2A

Table C.26.) A comparison with Figs. 6.12 and 6.14 for the case of immobile oil in the water layer shows that a small improvement in the oil production rate and oil-steam ratio occurs. The cumulative oil-steam ratio for the period simulated is nearly 30% higher than that for immobile oil. The oil recovery is 2% (Table C.26) as compared to 0.8% (ABRS2, Table 6.2) for the immobile oil case. As expected, the WOR is also lower because of some oil production from the water zone as well. The temperature profiles showed that heating of the water zone is to some extent greater than that of the oil zone (both have the same thickness and thermal properties). It can be conjectured that, if a bottom water zone contains a substantial volume of mobile oil, it may be feasible to develop a profitable steam injection process. Other variables to be examined in this regard are steam injection interval, rate, and quality, as functions of time.

Effect of Steam Injection Rate

Table 6.2 shows four runs (ABRS4, ABRS8, ABRS14, and ABRS10) utilizing twice the steam injection rate of the base run, i.e. 1200 B/D. The oil and water production histories, water-oil ratios, and oil-steam ratio for these runs are shown in Figs. 6.26 through 6.34 and Figs. 6.5 to 6.7. A comparison of the base run ABRS1 (Figs. 6.2 to 6.4) and ABRS4 (Figs. 6.26 to 6.28) shows that the oil recovery in the case of the higher steam injection rate is more than twice as large (14.6% vs. 6.25%) in the same time, i.e. 700 days (cum. inj. 420,000 bbl and 840,000 bbl), when there is no bottom water. This is due to faster and increased heating of the reservoir, with reduced gravity segregation of steam. The effect is noticeable in the oil-steam ratio, which increases from 0.25 (ABRS1) to 0.29 (ABRS4). This is a better criterion, because it shows that the real gain in oil production as a result of an increase in steam injection rate is smaller than the oil recovery figures indicate.

Figures 6.35 to 6.37 show the oil and water production histories, WOR, and oil-steam ratio for Run ABRS4A, which is similar to Run ABRS4, except that a bottom water

STEAMFLOOD RUN ABRS 4, ABERFELDY
NO BOTTOM WATER

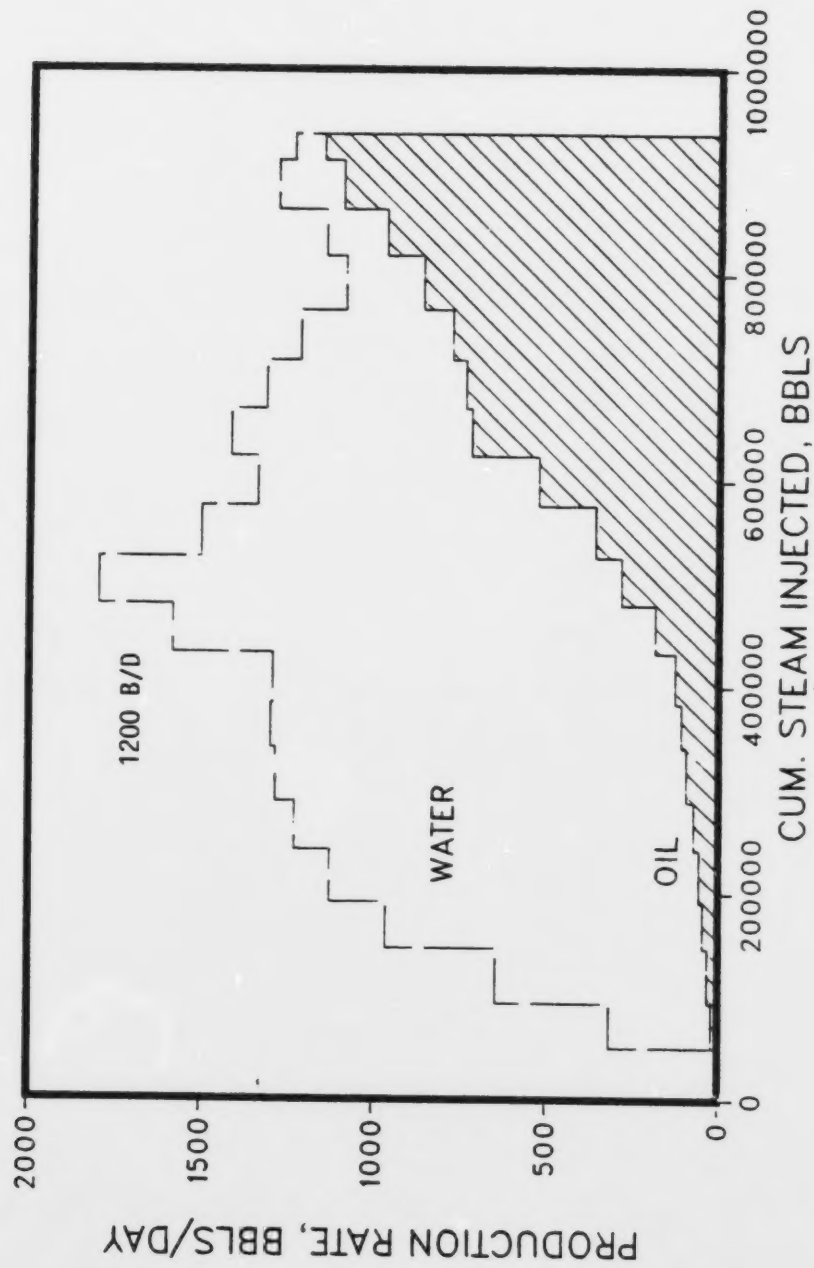


Figure 6.26 Production History of the Aberfeldy Steamflood ABRS4, No Bottom Water

STEAMFLOOD RUN ABRS 4, ABERFELDY
NO BOTTOM WATER

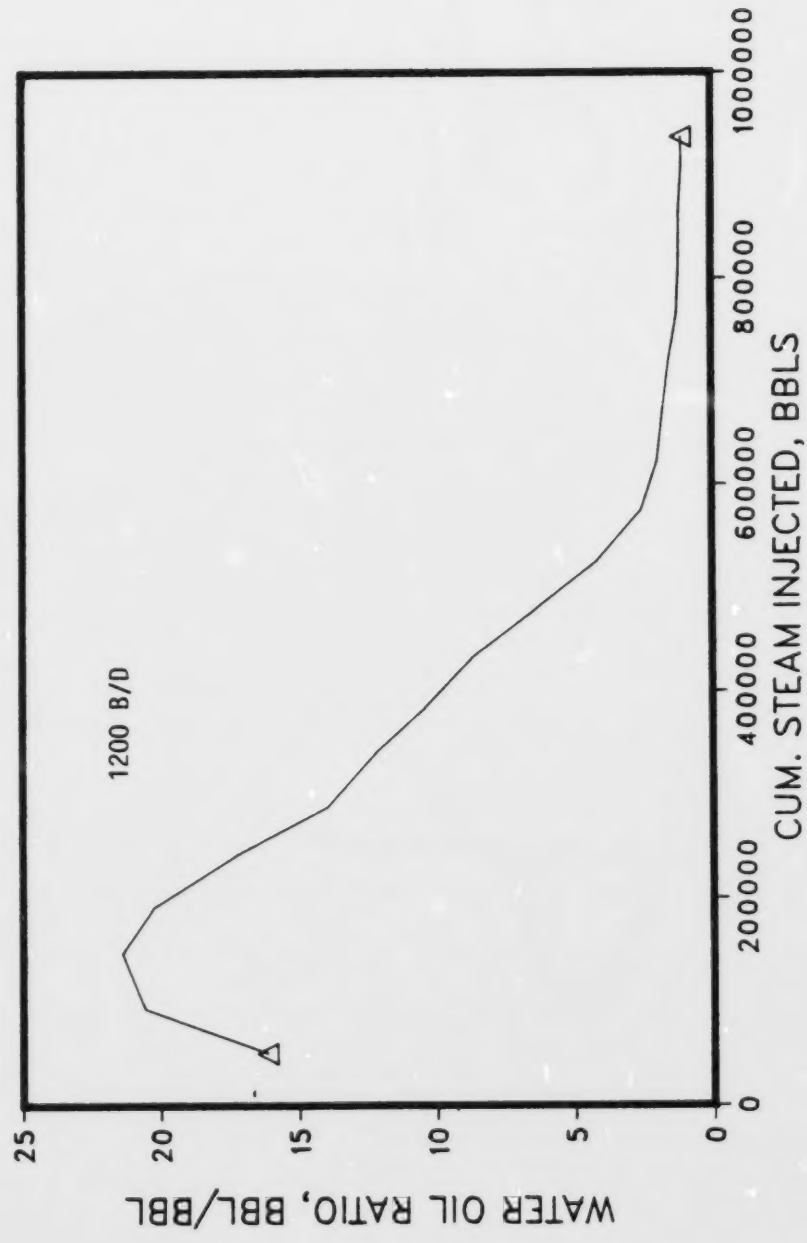


Figure 6.27 Water-Oil Ratio vs. Steam Injected for Aberfeldy Steamflood ABRS4

STEAMFLOOD RUN ABRS 4, ABERFELDY NO BOTTOM WATER

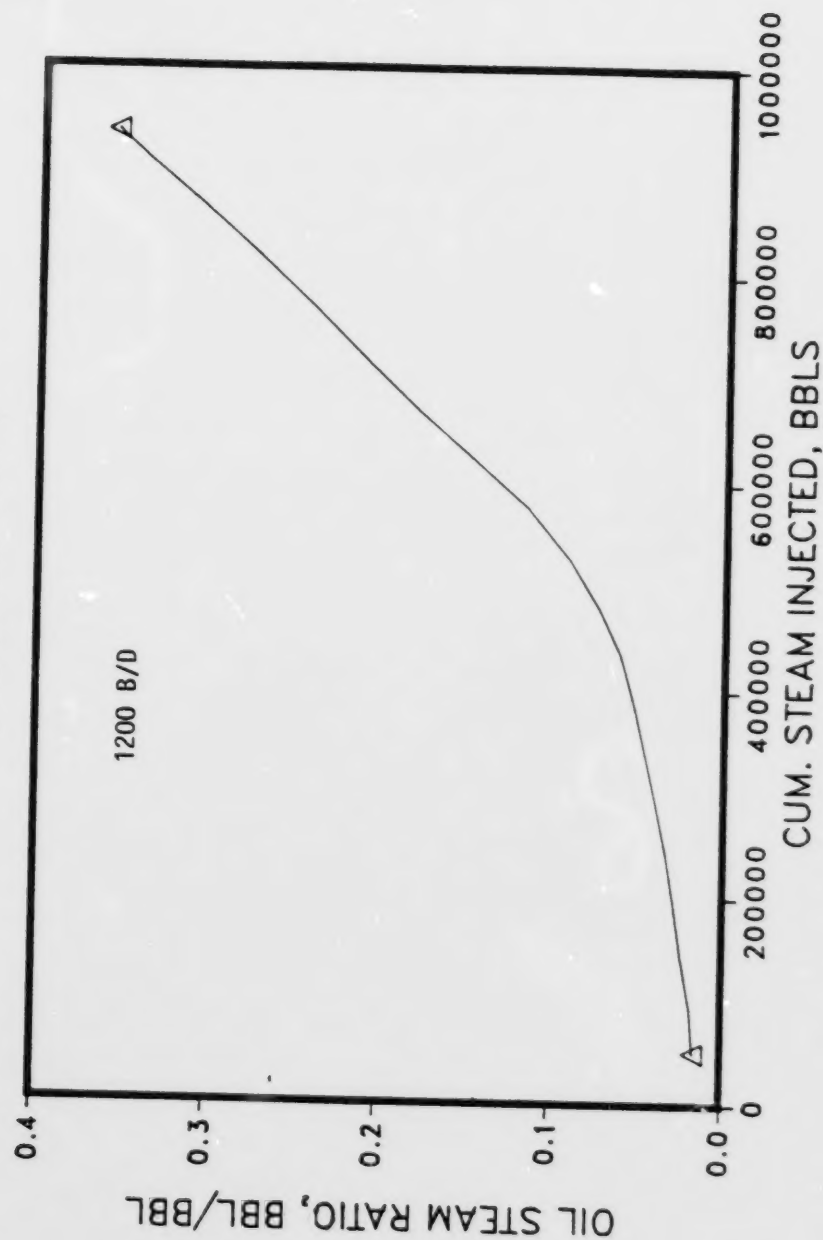


Figure 6.28 Oil-Steam Ratio vs. Steam Injected for Aberfeldy Steamflood ABRS4

STEAMFLOOD RUN ABRS 8, ABERFELDY NO BOTTOM WATER

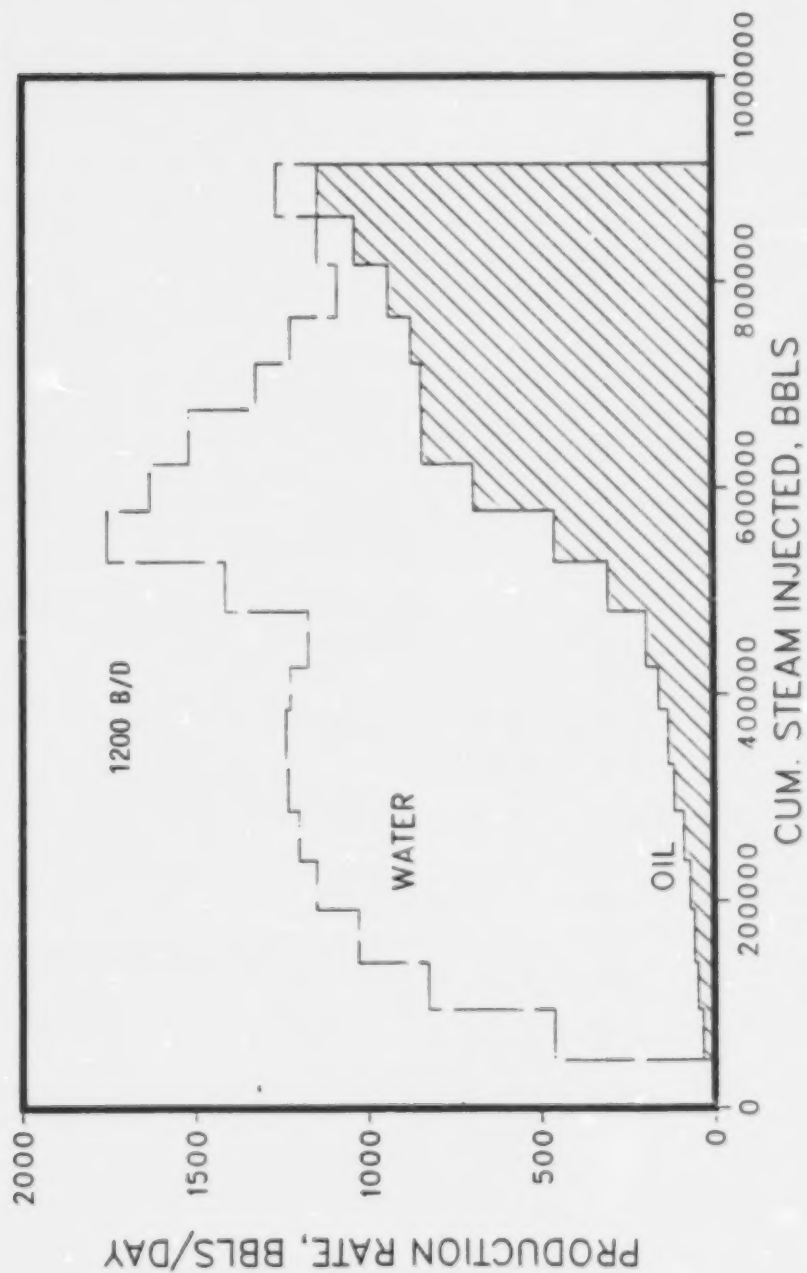


Figure 6.29 Production History of the Aberfeldy Steamflood ABRS8, No Bottom Water

STEAMFLOOD RUN ABRS 8, ABERFELDY
NO BOTTOM WATER

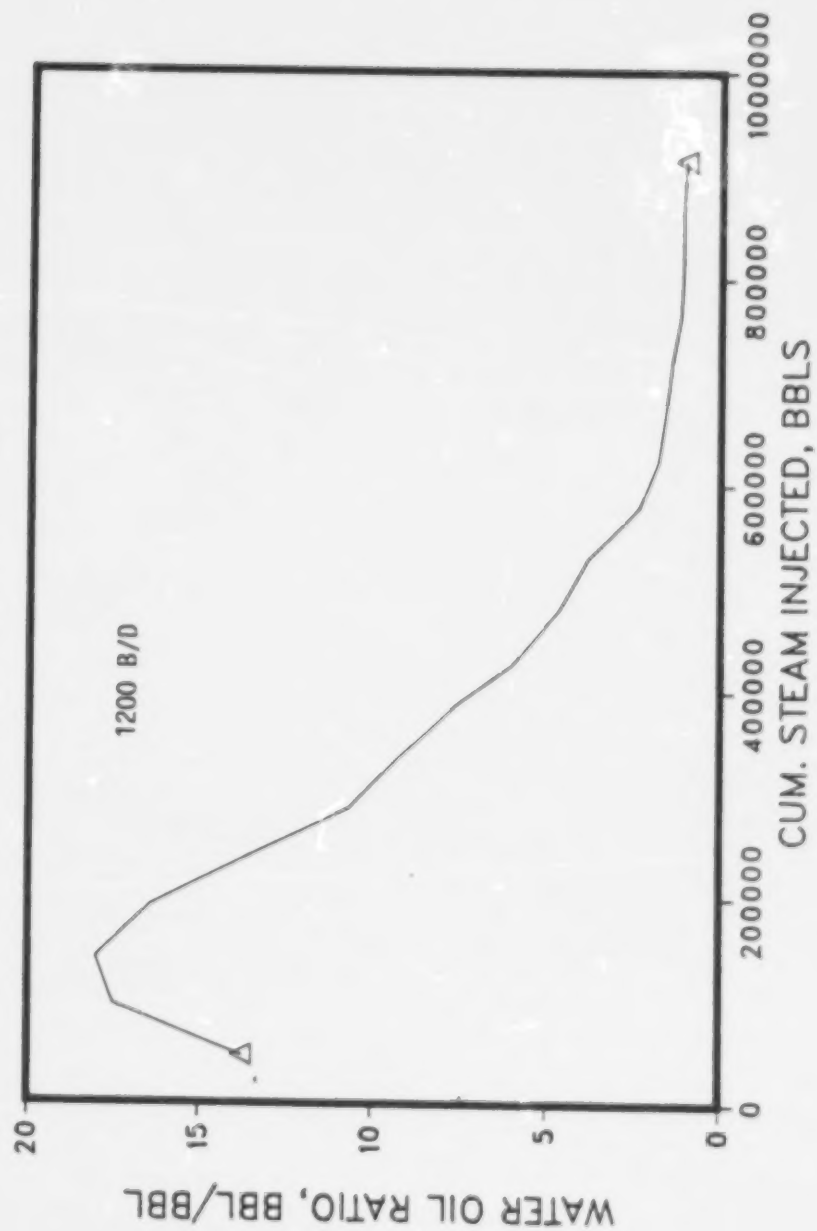


Figure 6.30 Water-Oil Ratio vs. Steam Injected for Aberfeldy Steamflood ABRS8

STEAMFLOOD RUN ABRS 8, ABERFELDY
NO BOTTOM WATER

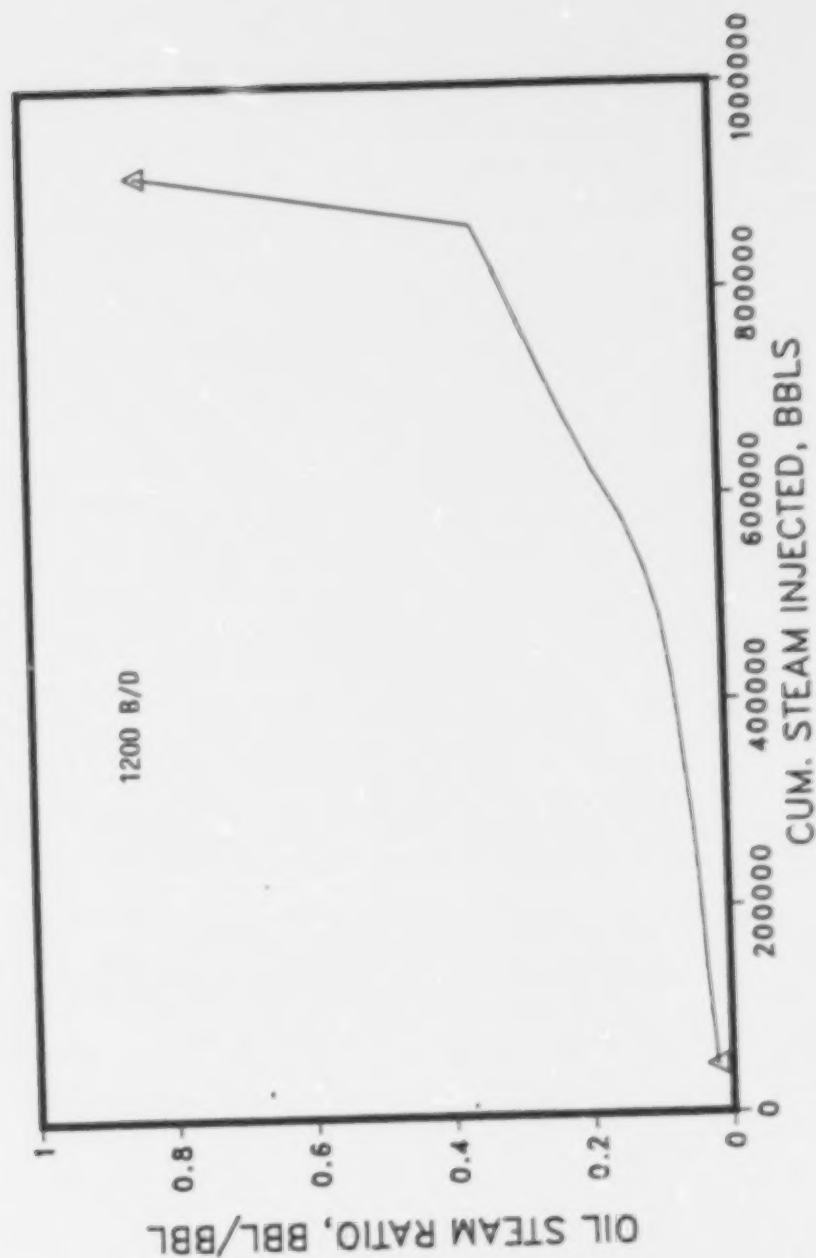


Figure 6.31 Oil-Steam Ratio vs. Steam Injected for Aberfeldy Steamflood ABRS8

STEAMFLOOD RUN ABRS 14, ABERFELDY NO BOTTOM WATER

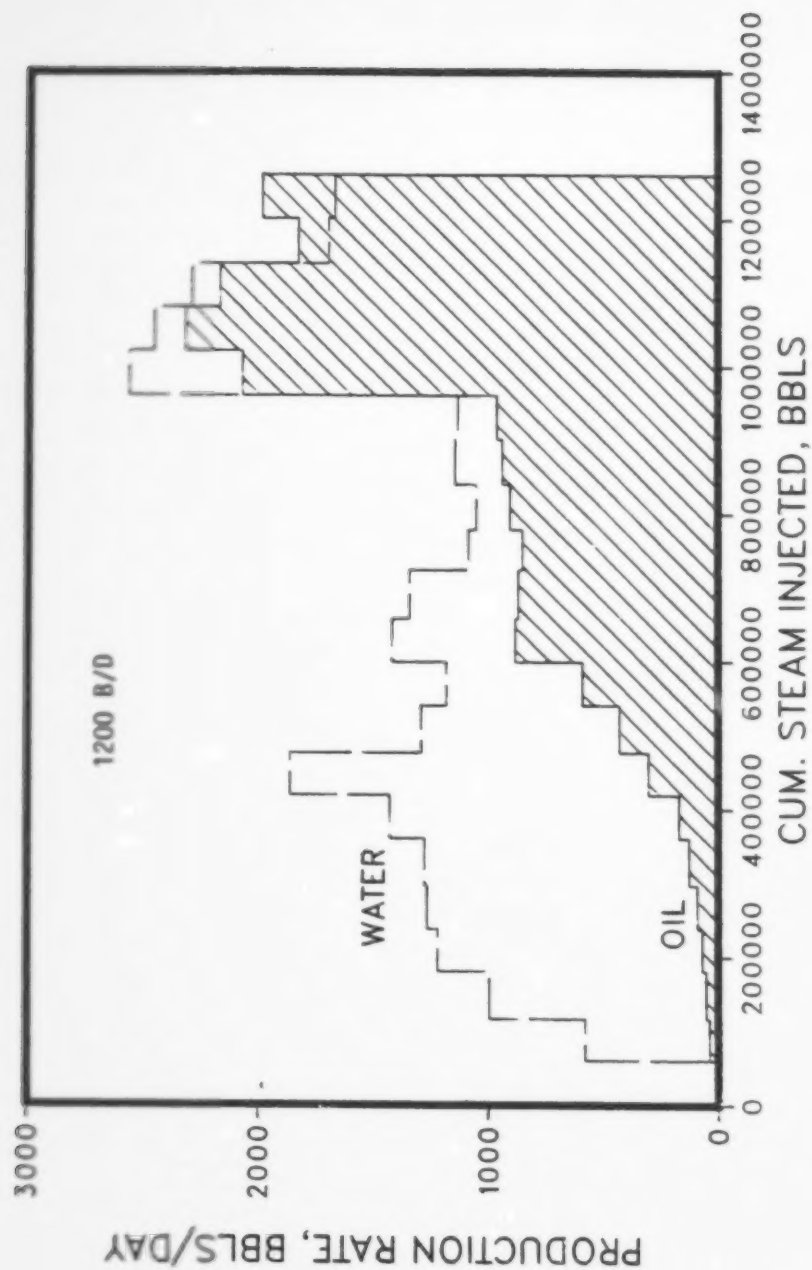


Figure 6.32 Production History of the Aberfeldy Steamflood ABRS14, No Bottom Water

STEAMFLOOD RUN ABRS 14, ABERFELDY
NO BOTTOM WATER

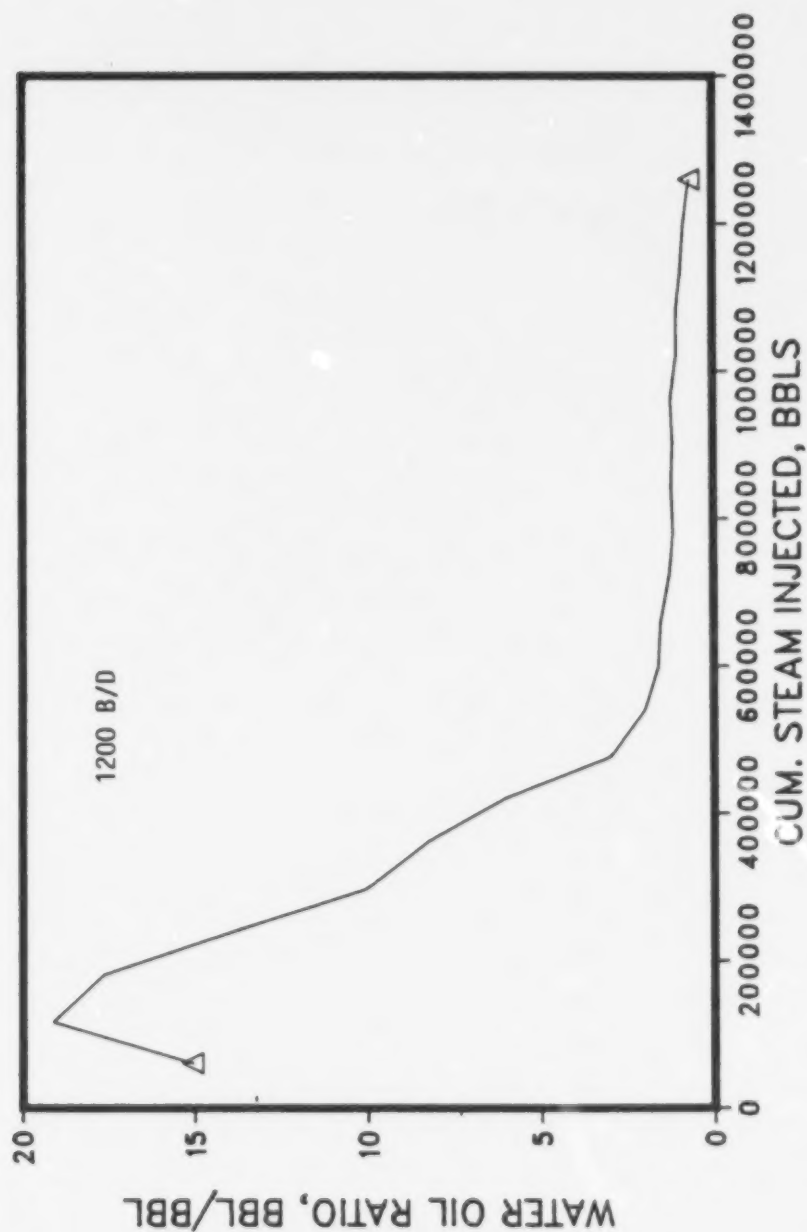


Figure 6.33 Water-Oil Ratio vs. Steam Injected for Aberfeldy Steamflood ABR14

STEAMFLOOD RUN ABRs 14, ABERFELDY NO BOTTOM WATER

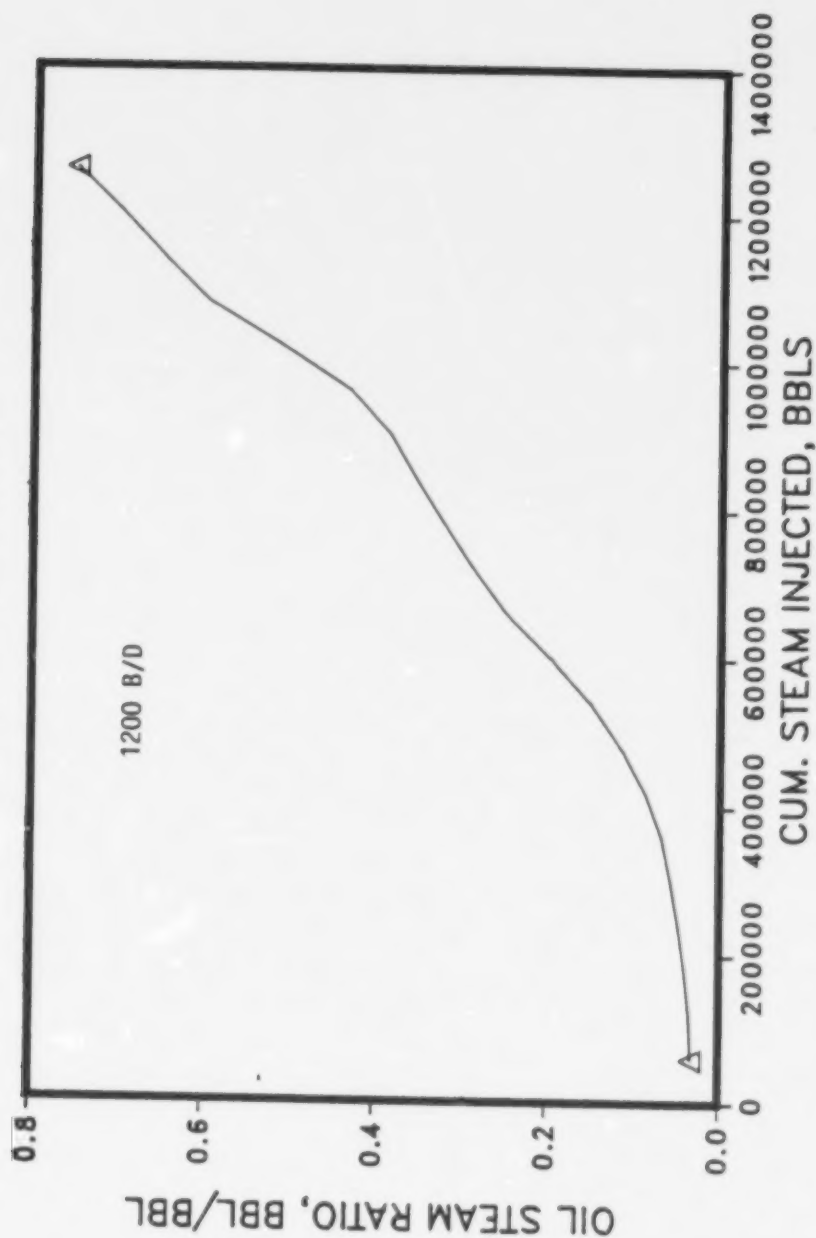


Figure 6.34 Oil-Steam Ratio vs. Steam Injected for Aberfeldy Steamflood ABRs 14

BOTTOM WATER, 36FT/36FT, STEAMFLOOD: ABERFELDY RUN ABR4A
 INJ. RATE 1200 BBLS/DAY; COMPLETED OVER ENTIRE INTERVAL

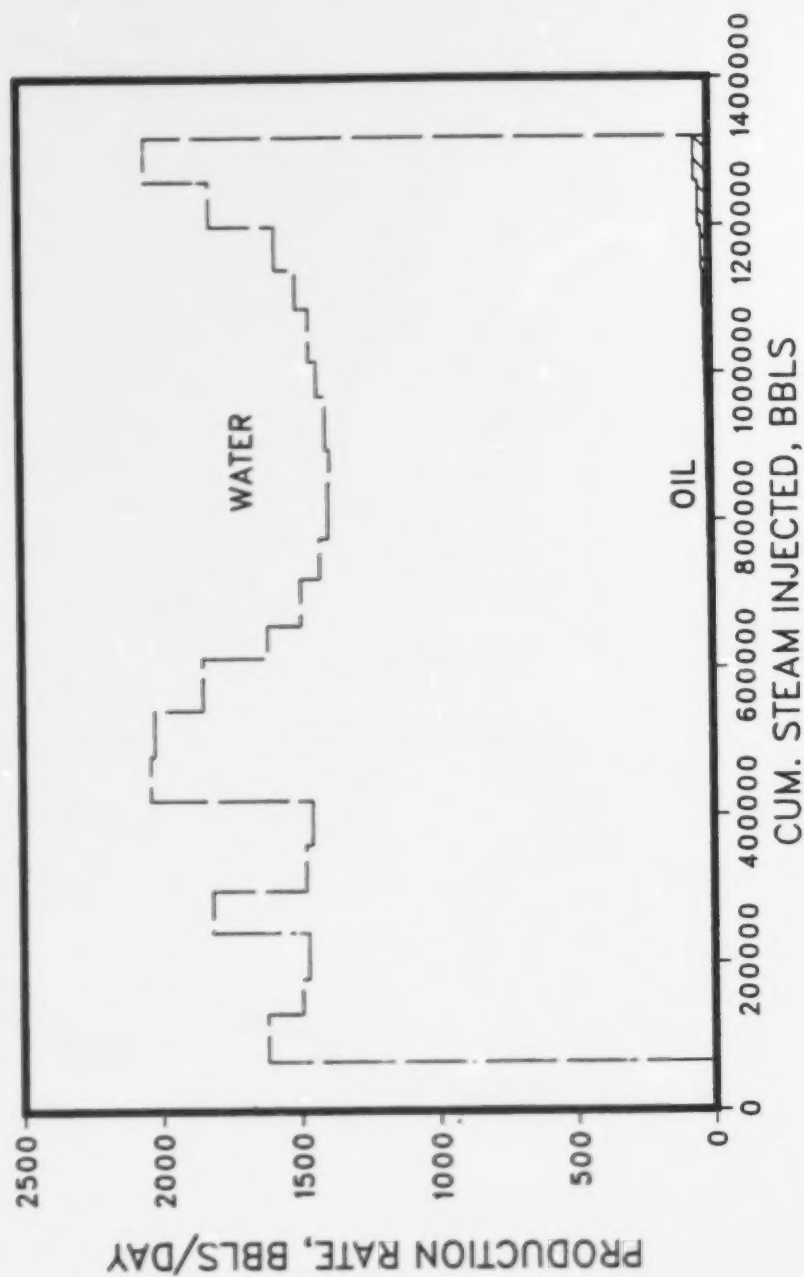


Figure 6.35 Production History of the Aberfeldy Steamflood ABR4A, Bottom Water

BOTTOM WATER, 36FT/36FT STEAMFLOOD: ABERFELDY RUN ABR4A
INJ. RATE 1200 BBL/DAY; COMPLETED OVER ENTIRE INTERVAL

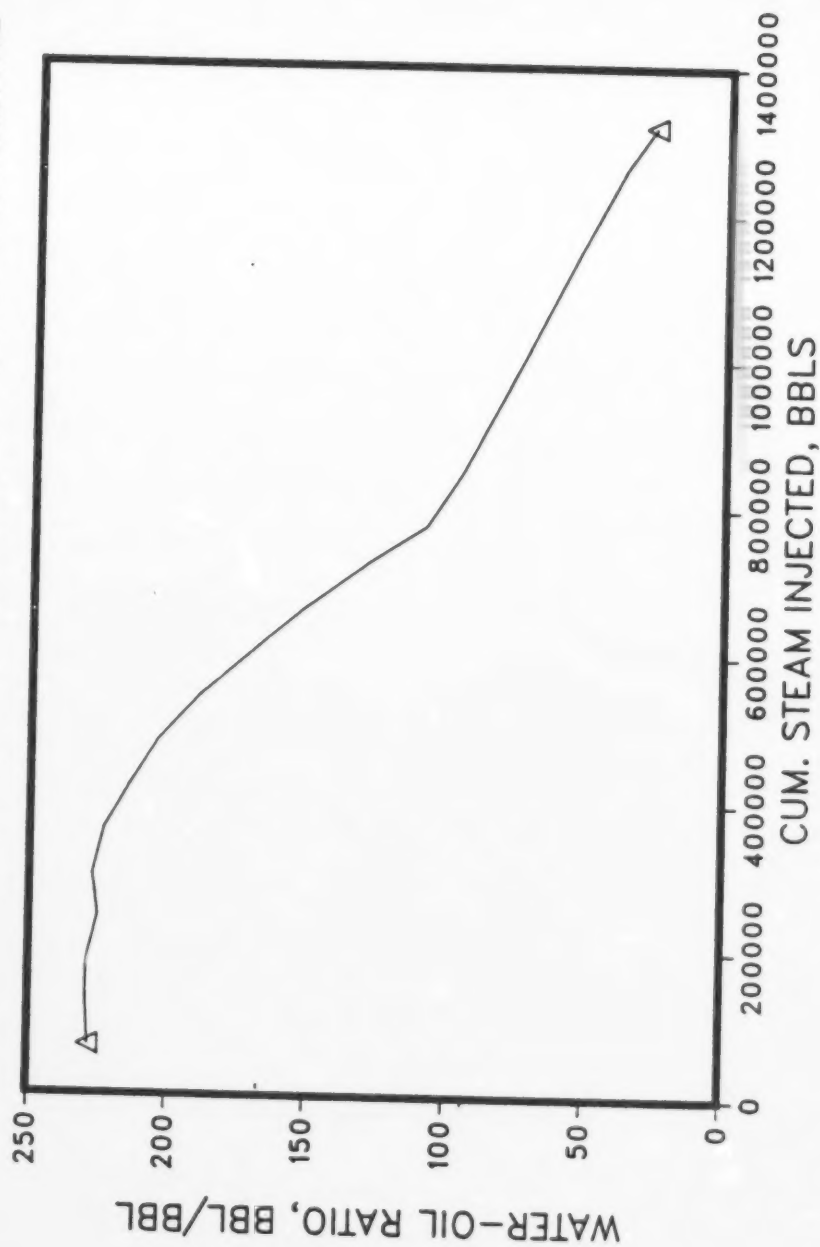


Figure 6.36 Water-Oil Ratio vs. Steam Injected for Aberfeldy Steamflood ABR4A

BOTTOM WATER, 36FT/36FT, STEAMFLOOD: ABERFELDY RUN ABR4A
INJ. RATE 1200 BBL/DAY; COMPLETED OVER ENTIRE INTERVAL

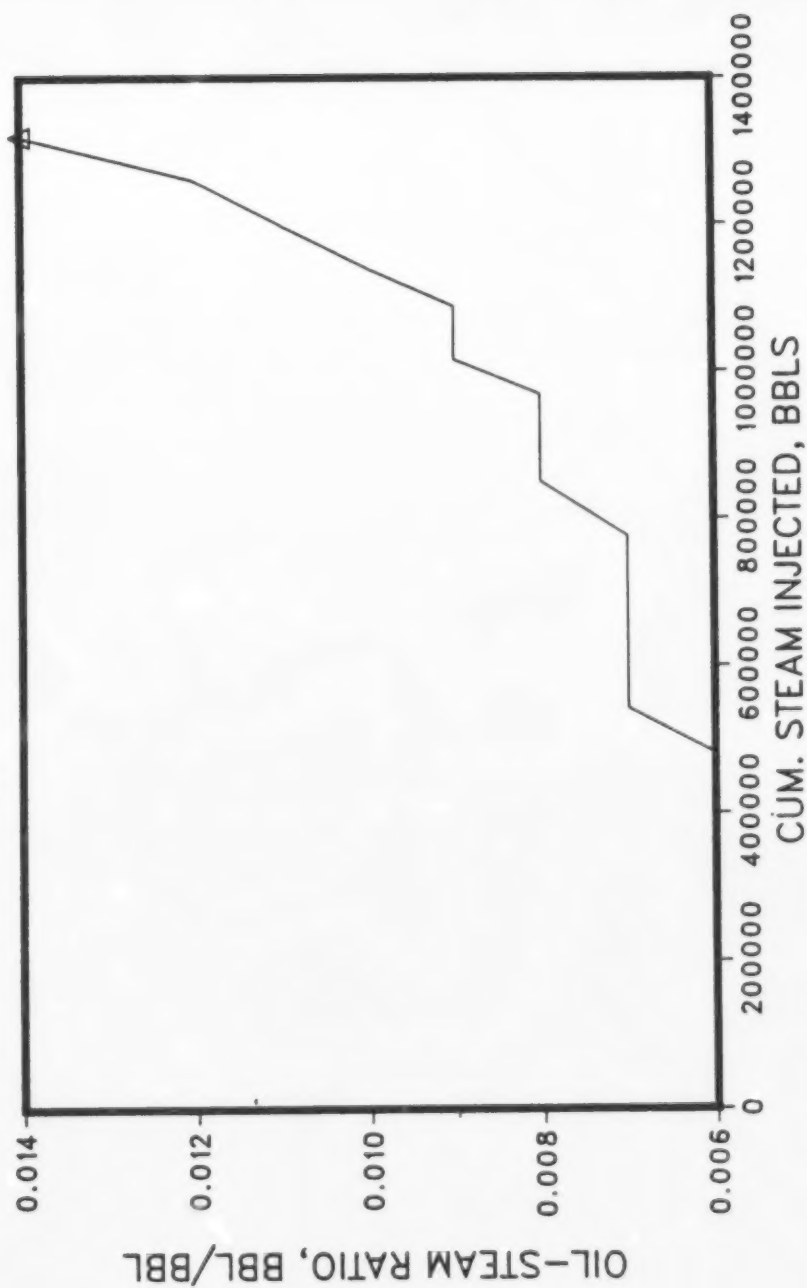


Figure 6.37 Oil-Steam Ratio vs. Steam Injected for Aberfeldy Steamflood ABR4A

layer of the same thickness as the oil zone is present. Figures 6.38 to 6.40 show similar plots for Run ABRS4B, in which the bottom water layer is one-tenth of the oil layer thickness. The difference in the performances of the three runs (ABRS4, ABRS4A, and ABRS4B) is remarkable. First, the thick water zone clearly leads to a large drop in the oil-steam ratio (0.0125 for ABRS4A vs. 0.290 for ABRS4) and oil recovery (0.85% for ABRS4A vs. 14.6% for ABRS4). This is due to the flow of steam in the water zone, which was found to be heated more than the oil zone. When the water zone thickness is reduced to one-tenth of the oil zone, the performance is actually improved for the high steam injection rate. The oil-steam ratio is now higher (0.352 for ABRS4B) than in the absence of bottom water. This is due to the fact that there is limited influx of steam into the water zone, with most of the steam going into the oil zone. At the same time, the heat from the water zone is conducted upward, mobilizing the colder oil above. As a result, the overall performance is actually improved due to the presence of water.

For a given oil, and for a given steam injection rate, there would be some optimal bottom water zone thickness that improves overall performance of a steamflood. A thin water zone would be beneficial for promoting steam injectivity in the case of a very viscous oil. But if the water zone is too thin, it will become saturated with the oil driven from the oil zone above, thus leading to a drop in steam injectivity. On the other hand, a thick water zone will act as a heat sink, leading to poor performance.

Effect of Vertical Permeability

An important factor in bottom water steamfloods is the vertical permeability of the oil/water formations. Obviously, a vertical permeability of zero is desirable, which will be the case if a shale barrier is present between the oil and water layers. If the vertical permeability is less than the horizontal permeability, then the performance would depend on the actual value. Up to a point, a reduction in the vertical permeability may not have a noticeable beneficial effect on performance, because steam still reaches the water zone.

BOTTOM WATER STEAMFLOOD, 36FT/3.6FT : ABERFELDY RUN ABR4B
 INJ. RATE 1200 BBL/DAY; COMPLETED OVER ENTIRE INTERVAL

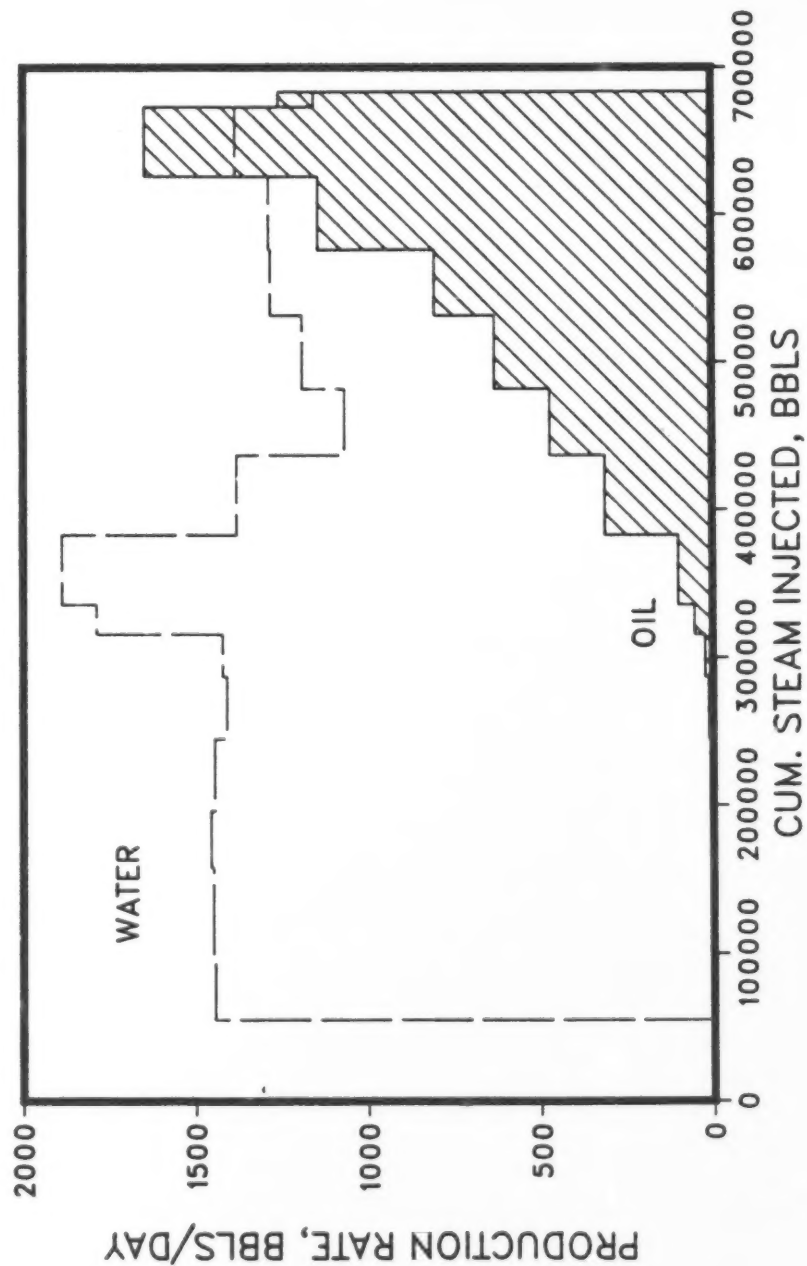


Figure 6.38 Production History of the Aberfeldy Steamflood ABR4B, Bottom Water

BOTTOM WATER STEAMFLOOD, 36FT/3.6FT : ABERFELDY RUN ABRS4B
INJ. RATE 1200 BBL/DAY; COMPLETED OVER ENTIRE INTERVAL

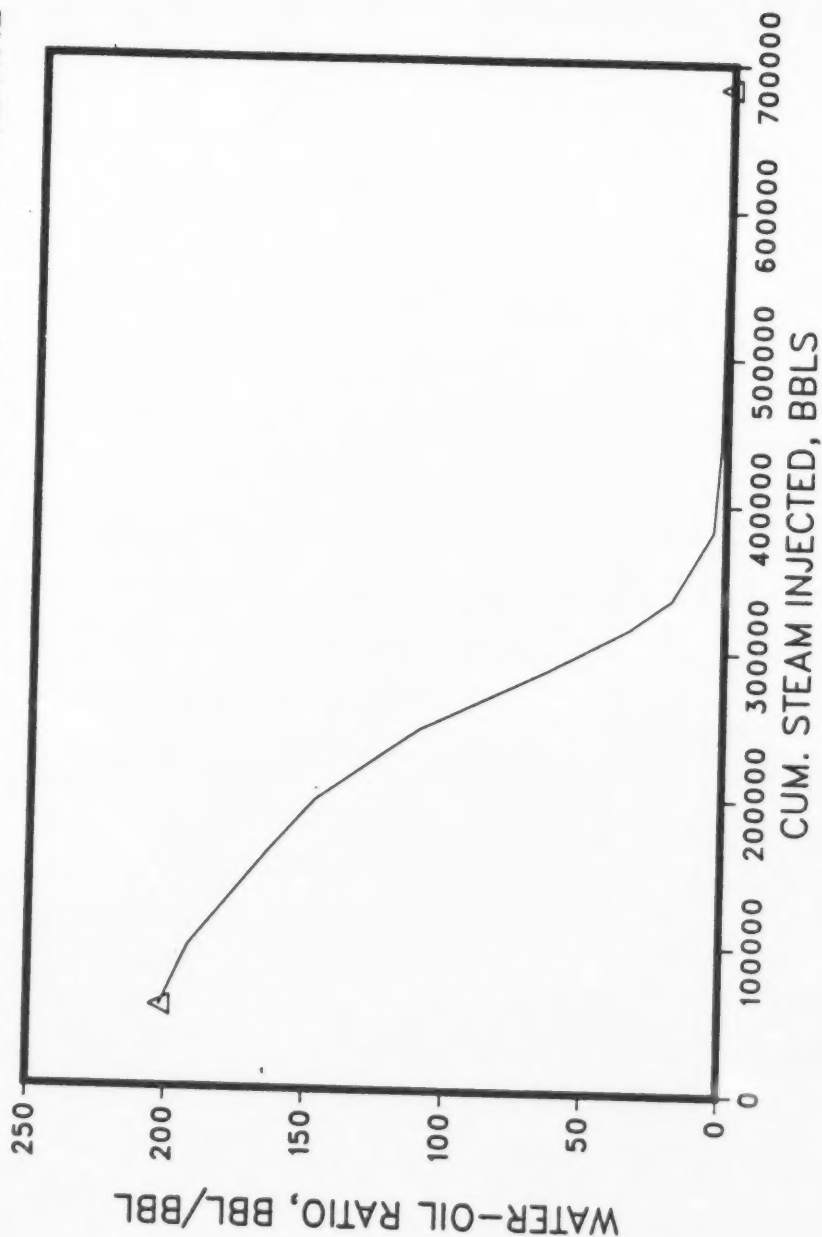


Figure 6.39 Water-Oil Ratio vs. Steam Injected for Aberfeldy Steamflood ABRS4B

BOTTOM WATER STEAMFLOOD, 36FT/3.6FT : ABERFELDY RUN ABR4B
INJ. RATE 1200 BBLS/DAY; COMPLETED OVER ENTIRE INTERVAL

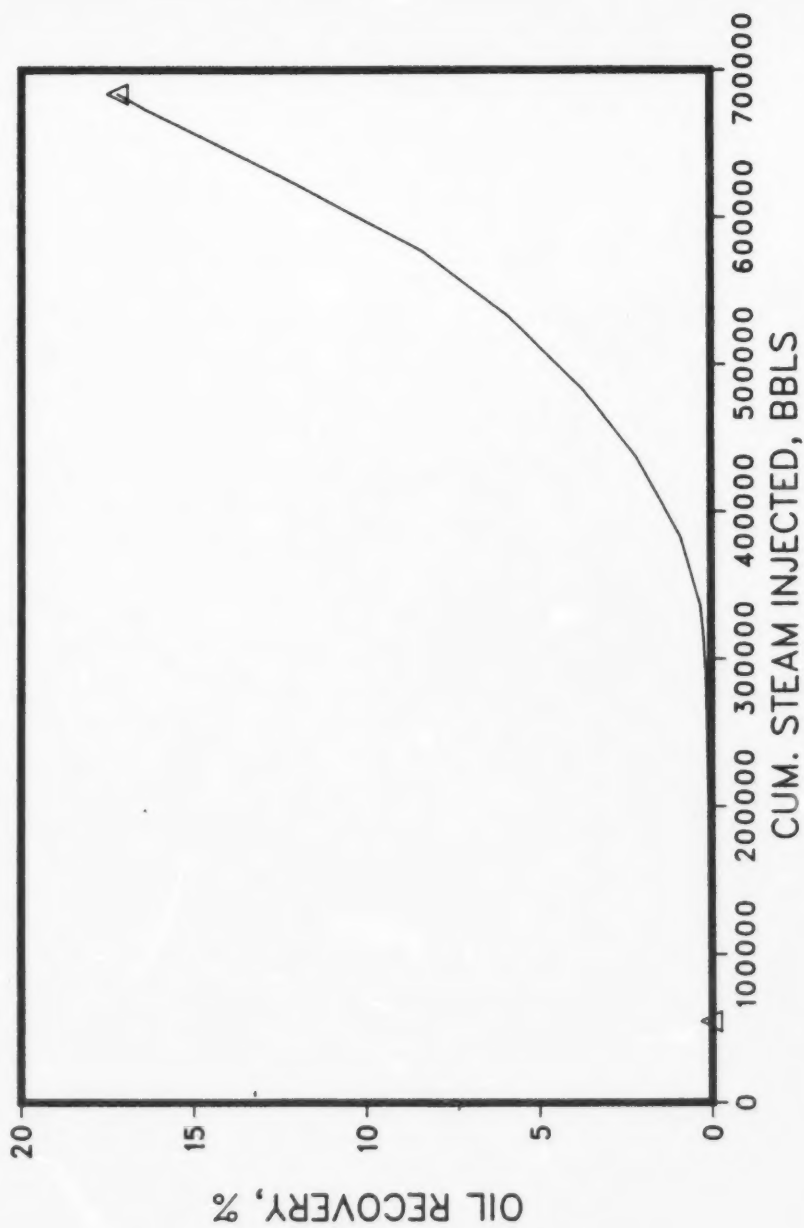


Figure 6.40 Oil Recovery vs. Steam Injected for Aberfeldy Steamflood ABR4B

This was noted in the simulations conducted. Figures 6.21 to 6.23 and 6.41 through 6.43 show the oil and water production, WOR, and oil-steam ratio plots for Runs ABR57 and ABR515, in which the vertical permeability was reduced by a factor of 5, compared to the horizontal permeability. The bottom water zone was one-third and one-fifth of the oil zone, respectively. The performance of these two runs can be compared with that of the base Run ABR51. It is seen that the reduced vertical permeability did not help much. The oil-steam ratio is 0.075 and 0.092, respectively, compared to 0.25 in the absence of bottom water. If we compare the performance of ABR515 (oil-steam ratio 0.092) with reduced vertical permeability (one-fifth) to that of ABR55 (oil-steam ratio 0.113), with equal permeabilities in all directions, it is seen that the reduced permeability actually gives a slightly lower oil-steam ratio and oil recovery (in both cases $h_w/h_o = 0.2$). While this difference may not be significant because of numerical limitations, one possible explanation is that the oil driven into the water zone below (wells are completed in the oil zone only) is restricted from flowing back into the oil zone due to lower vertical permeability.

In Run ABR516, the vertical permeability was reduced by a factor of 10 relative to the horizontal permeabilities (Table C.13). The performance is clearly improved in this case (oil-steam ratio is 0.627). It seems that the small amount of steam flowing in the water layer is helpful in conductive heating of the oil zone above, so that the cold oil is mobilized and driven efficiently into the producers.

Effect of Completion Interval

In steamflooding, the completion interval of the steam injection wells and the producers has an important effect on performance (oil recovery, oil-steam ratio, water-oil ratio, etc.). This is so because the vertical sweep, and the fluid and heat distributions will depend on the injection/production intervals. In all of the steamfloods discussed above, where bottom water was not present, the steam injection and production wells were completed in the entire interval. When bottom water was present, the wells were completed

STEAMFLOOD RUN ABRS 15, ABERFELDY
BOTTOM WATER

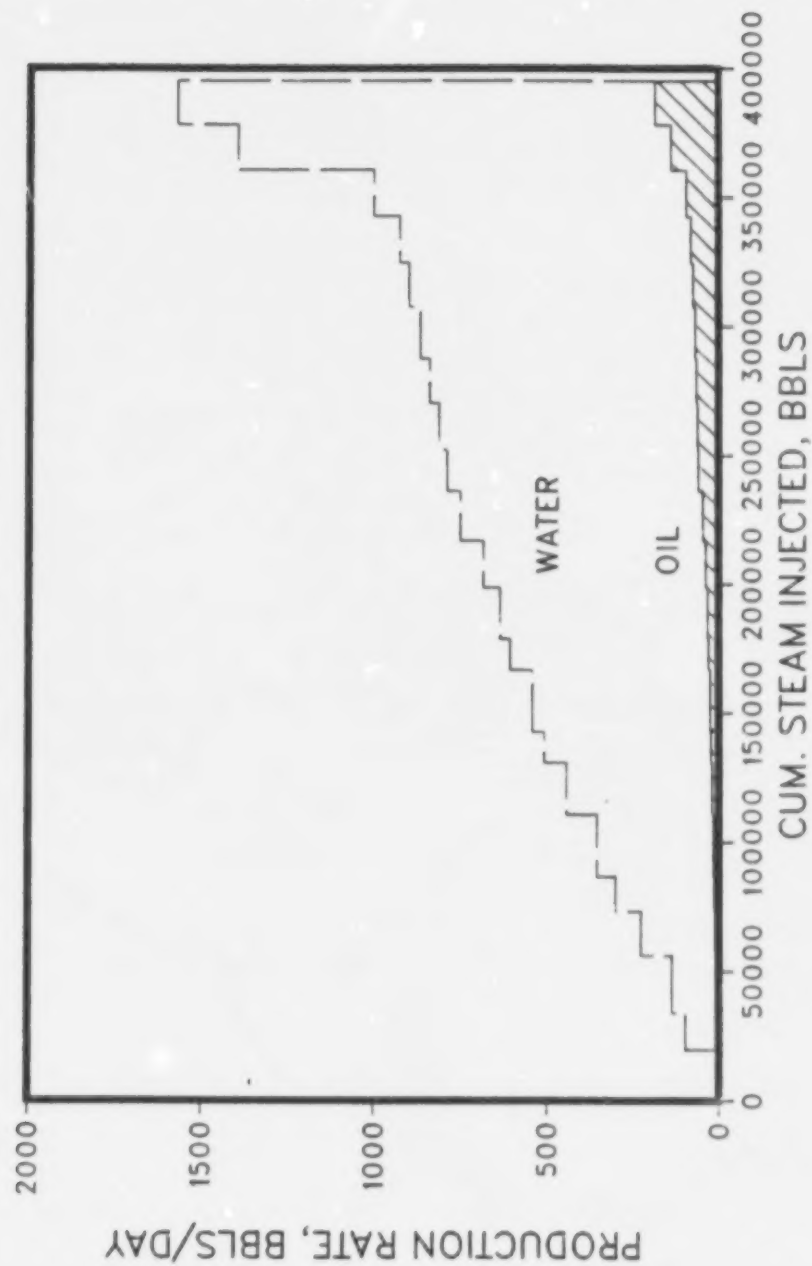


Figure 6.41 Production History of the Aberfeldy Steamflood ABRS15, Bottom Water

STEAMFLOOD RUN ABRS 15, ABERFELDY BOTTOM WATER

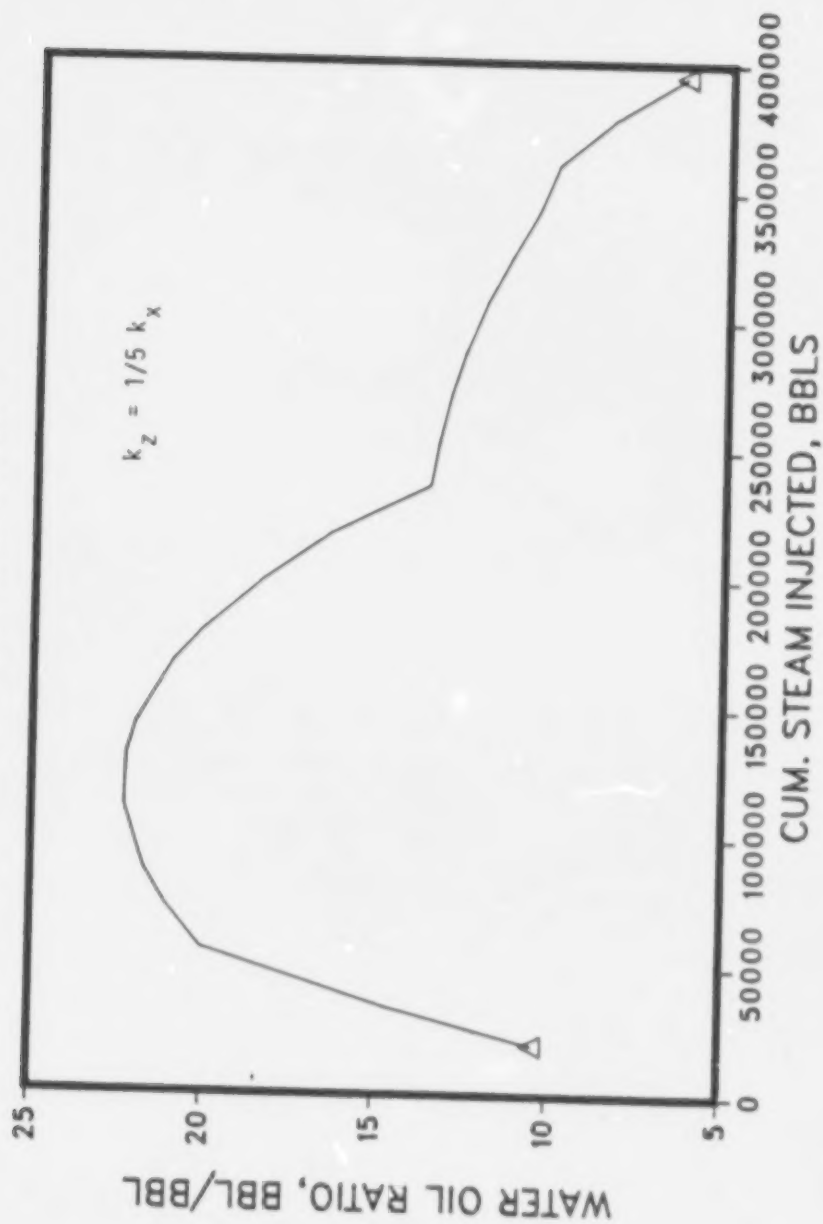


Figure 6.42 Water-Oil Ratio vs. Steam Injected for Aberfeldy Steamflood ABRS15

STEAMFLOOD RUN ABRs 15, ABERFELDY
BOTTOM WATER

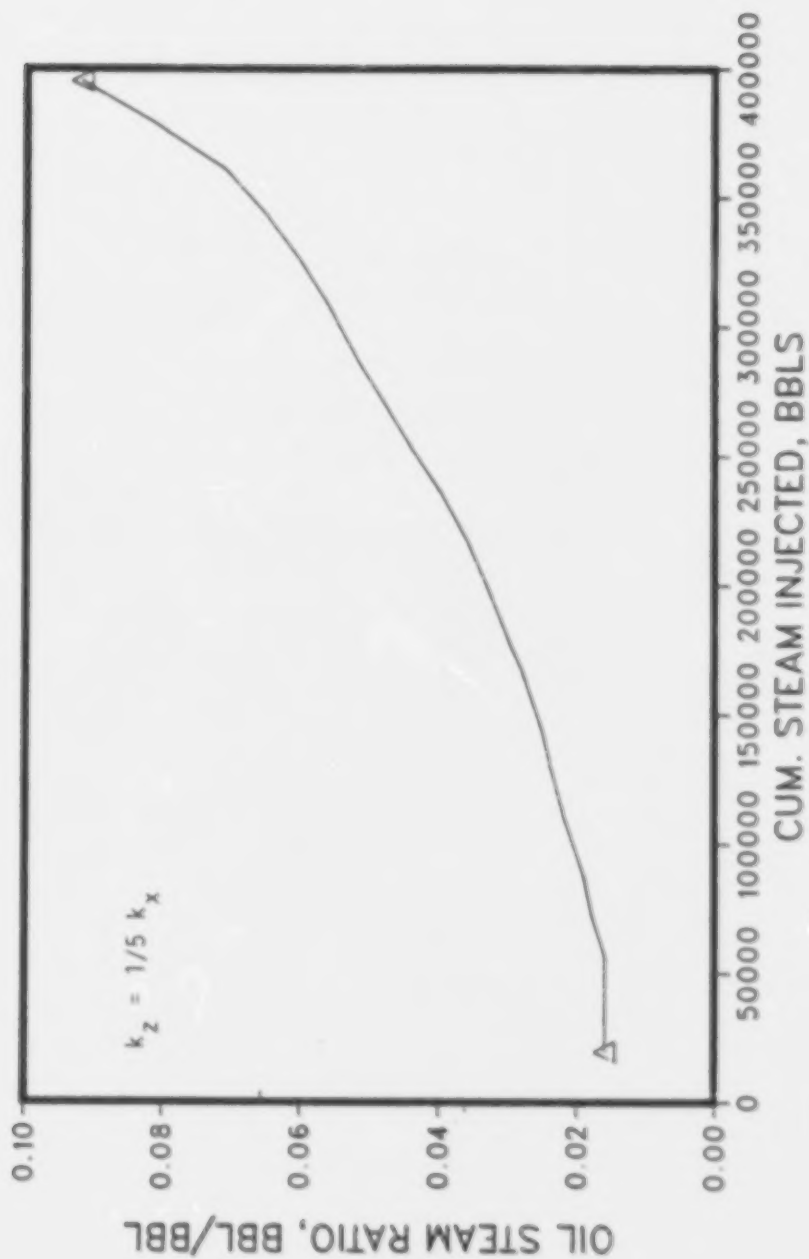


Figure 6.43 Oil-Steam Ratio vs. Steam Injected for Aberfeldy Steamflood ABRs15

only in the oil zone. As an example of a different type of completion, Run ABR51B (Table C.27) is presented. In this run, there is no bottom water, and the injection well is completed in the lower part of the formation only. In this manner, steam would first heat the lower part of the formation, then rise, and heat the upper part. In contrast, the injection well completion in Run ABR51 was across the entire formation, and as a result, steam segregation occurred early during the flood. Figures 6.44 to 6.46 show the performance curves for Run ABR51B, and a comparison with Figs. 6.2 to 6.4 shows that injection in the lower part of the formation did improve oil-steam ratio (0.39 vs. 0.25), oil recovery (11% vs. 6.25%), and WOR. Many other types of completion schemes can be tested: e.g. completion at two points in the oil zone, completion of producers initially in the lower part of the oil zone, and at a later time over the entire interval (when bottom water is present), injection well completion in the oil zone and completion of producers in the water zone (case of reverse coning), as well as various partial penetration schemes.

Cyclic Steam Stimulation: Aberfeldy

Many cyclic steam stimulation simulations were carried out to examine the effects of selected variables, for the Aberfeldy and Cold Lake reservoirs. The main variables in the cyclic steaming process are: steam slug size, steam pressure, quality, injection rate, soak time, injection interval, wellbore completion, production period, well operating conditions, number of cycles, increasing/decreasing/constant steam slug sizes for succeeding cycles, formation fracturing, bottom water effects, use of additives with steam, partial penetration, etc. A few of these variables were studied in this work.

Tables 6.3 (a) and (b) summarize the principal results of cyclic steam stimulation simulations conducted. The run termination criterion was a preset (200 sec) computer time. Only in a few instances were runs as long as 500 sec conducted.

Tables C.14 to C.17 and Figs. 6.47 through 6.58 summarize results of cyclic steam stimulation simulations for the Aberfeldy formation, for the case of no bottom water. The

PARTIAL PENETRATION STEAMFLOOD: ABERFELDY RUN ABR18; NO BW
 INJ. RATE 600 BBLS/DAY; INJ OVER LOWER ONE-HALF INTERVAL

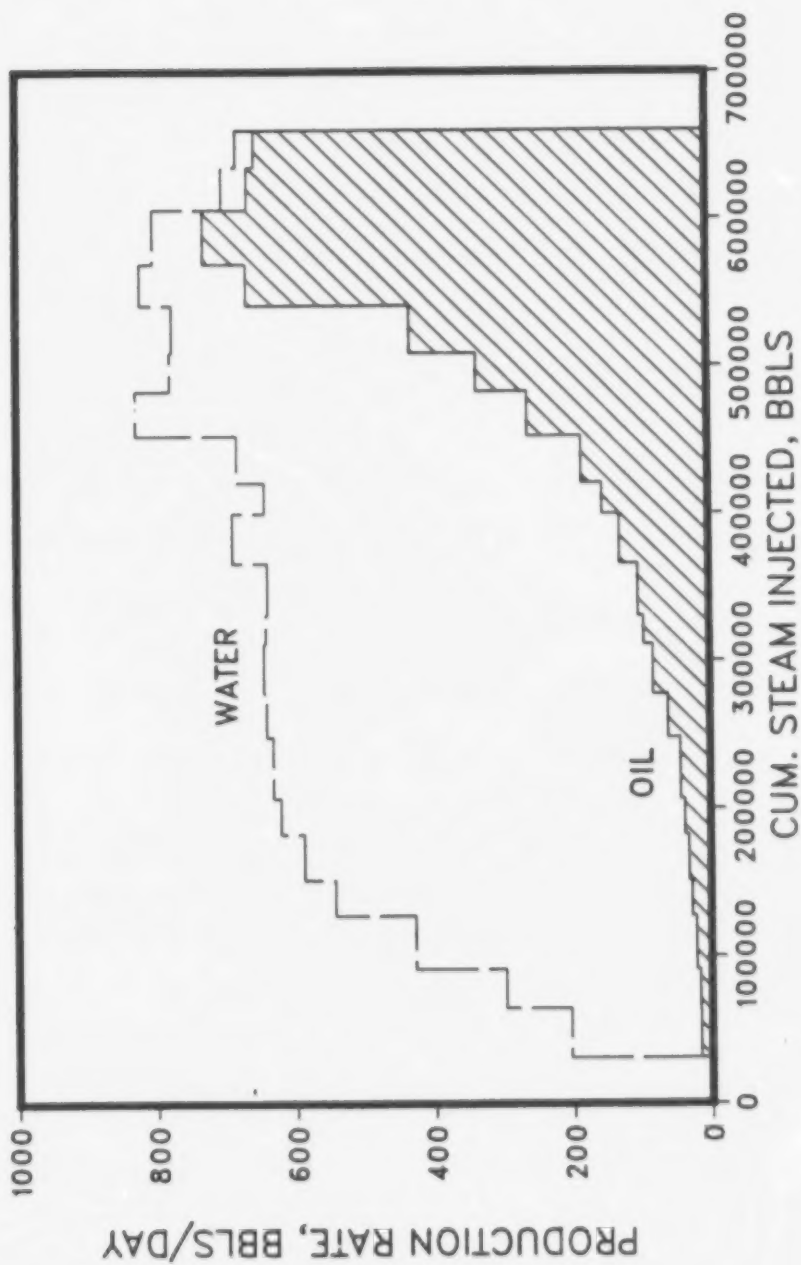


Figure 6.44 Production History of the Aberfeldy Steamflood ABR18, No Bottom Water.

PARTIAL PENETRATION STEAMFLOOD: ABERFELDY RUN ABR51B; NO BW
INJ. RATE 600 BBL5/DAY; INJ OVER LOWER ONE-HALF INTERVAL

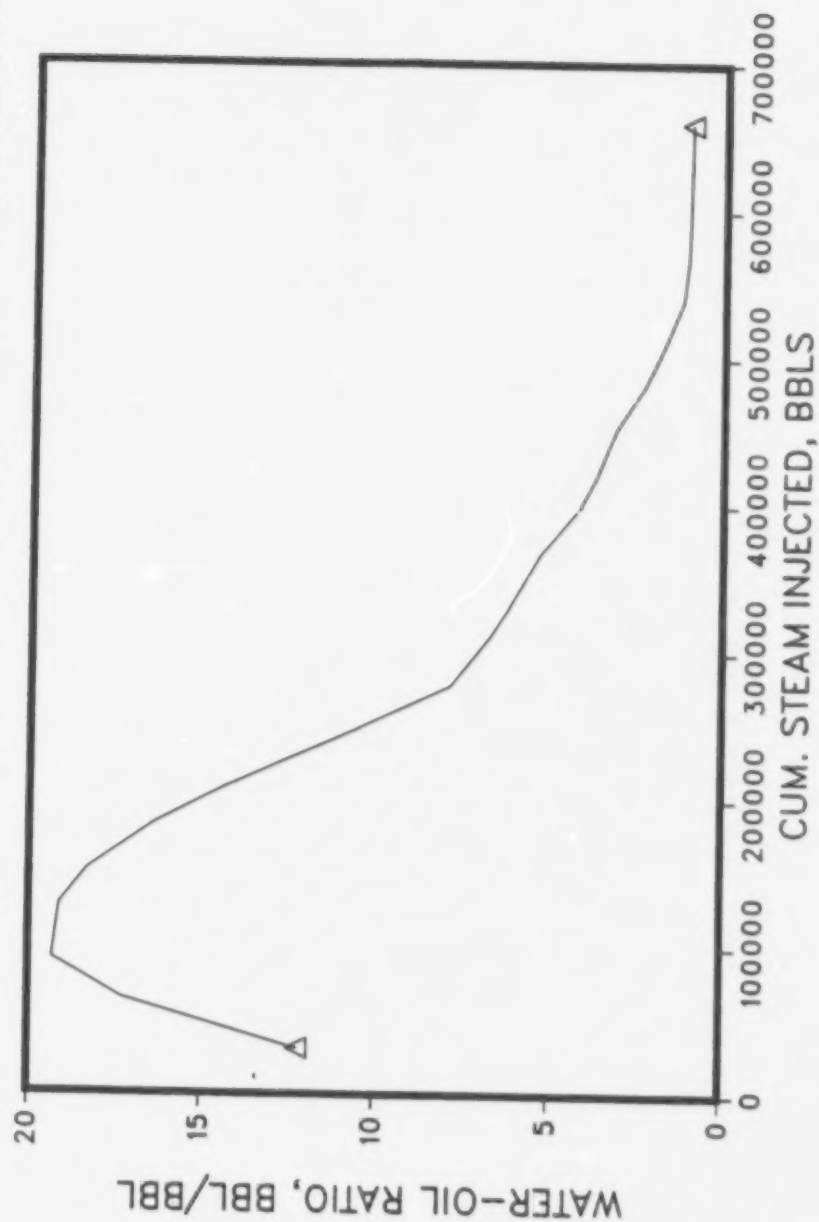


Figure 6.45 Water-Oil Ratio vs. Steam Injected for Aberfeldy Steamflood ABR51B

PARTIAL PENETRATION STEAMFLOOD: ABERFELDY RUN ABR51B; NO BW
INJ. RATE 600 BBL/DAY; INJ OVER LOWER ONE-HALF INTERVAL

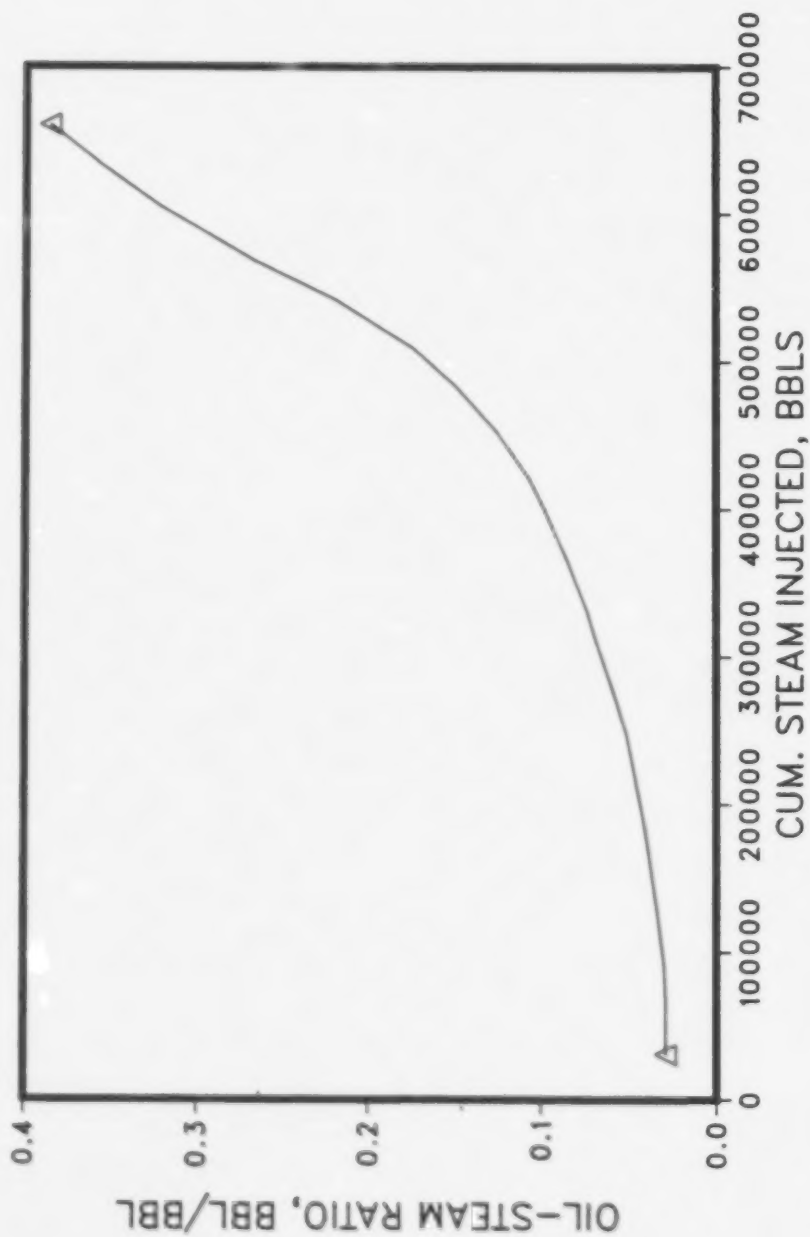


Figure 6.46 Oil-Steam Ratio vs. Steam Injected for Aberfeldy Steamflood ABR51B

Table 6.3 (a)

ABERFELDY CYCLIC STEAMING RUNS & CONDITIONS

Run	Cycle 1			Cycle 2			Cycle 3			Conditions	Notes
	Injection Time	Soak Time	Production Time	Injection Time	Soak Time	Production Time	Injection Time	Soak Time	Production Time		
ABC1	30	5	90	30	5	90	30	5	90	no bottom water	1,2
ABC2	30	5	90	40	5	90	50	5	90	no bottom water	3
ABC3	30	5	90	20	5	90	10	5	90	no bottom water	4
ABC4	30	20	90	30	20	90	30	20	90	no bottom water	5
ABC6	30	5	90	30	5	90	30	5	90	thin bottom water	1,2
ABC8	30	5	90	20	5	90	10	5	90	thin bottom water	3
ABC9	30	20	90	30	20	90	30	20	90	thin bottom water	4
ABC11	30	5	90	30	5	90	30	5	90	thick bottom water	1,2
ABC17	30	5	90	30	5	90	30	5	90	thick bottom water	3
ABC18	30	5	90	30	5	90	30	5	90	thick bottom water	4,6

Note 1: Injection time 30 days, soak time 5 days

Note 2: Same condition in all cycles

Note 3: Injection time 30 days in Cycle 1, 40 days in Cycle 2 and 50 days in Cycle 3, soak time, 5 days

Note 4: Injection time 30 days in Cycle 1, 20 days in Cycle 2 and 10 days in Cycle 3, soak time, 5 days

Note 5: Injection time 30 days, long soak times (20 days), in all cycles

Note 6: Well completed in the upper one-half of the oil zone

Table 6.3 (b)
ABERFELDY CYCLIC RUNS RESULTS SUMMARY

Run	$\frac{h_w}{h_{oil}}$	Perfs.	Cycle 1				Cycle 2				Cycle 3				Notes
			time.day	OSR	Cum	Oil	Prod.	OSR	Cum.	Oil	Prod.	OSR	Cum.	Oil	
				Bbl/Bbl	WOR	Rec.%	time.day	Bbl/Bbl	WOR	Rec.%	time.day	Bbl/Bbl	WOR	rec.%	
ABC1	0	1-2	90	0.103	10.2	.32	0	-	-	-	0	-	-	-	1,2
ABC2	0	1-2	90	.151	8.65	.40	90	.086	76.9	.53	7	.053	21.3	.565	3
ABC3	0	1-2	90	.151	8.65	.40	90	.132	26.2	.59	90	.1254	27.62	.67	4
ABC4	0	1-2	90	.1408	8.75	.38	20	.0874	25.11	.47	0	-	-	-	5
ABC6	0.1	1-1	90	.058	31.17	.15	90	.0593	57.6	.30	10	.044	24.2	.34	1,2
ABC8	0.1	1-1	90	.058	31.17	.15	90	.079	14.77	.34	90	.091	17.11	.47	3
ABC9	0.1	1-1	90	.055	32.12	.14	17	.0395	20.4	.20	0	-	-	-	4
ABC11	1.0	1-1	90	.082	16.8	.158	90	.0477	374.	.184	0	-	-	-	1,2
ABC17	1.0	1-1	90	.081	16.53	.155	90	.054	132.8	.206	13	.038	126.7	.221	3
ABC18	1.0	1-1	90	.0056	3.85	.011	90	.0114	4.60	.044	90	.022	2.97	.129	3,6

Note 1: Injection time 30 days, soak time 5 days

Note 2: Same condition in all cycles

Table 6.3 (b) continued

Note 3:	Injection time 30 days in Cycle 1, 40 days in Cycle 2 and 50 days in Cycle 3, soak time, 5 days
Note 4:	Injection time 30 days in Cycle 1, 20 days in Cycle 2 and 10 days in Cycle 3, soak time, 5 days
Note 5:	Injection time 30 days, long soak times (20 days), in all cycles
Note 6:	Well completed in the upper one-half of the oil zone

CYCLIC STEAMING RUN ABC 1, ABERFELDY
NO BOTTOM WATER

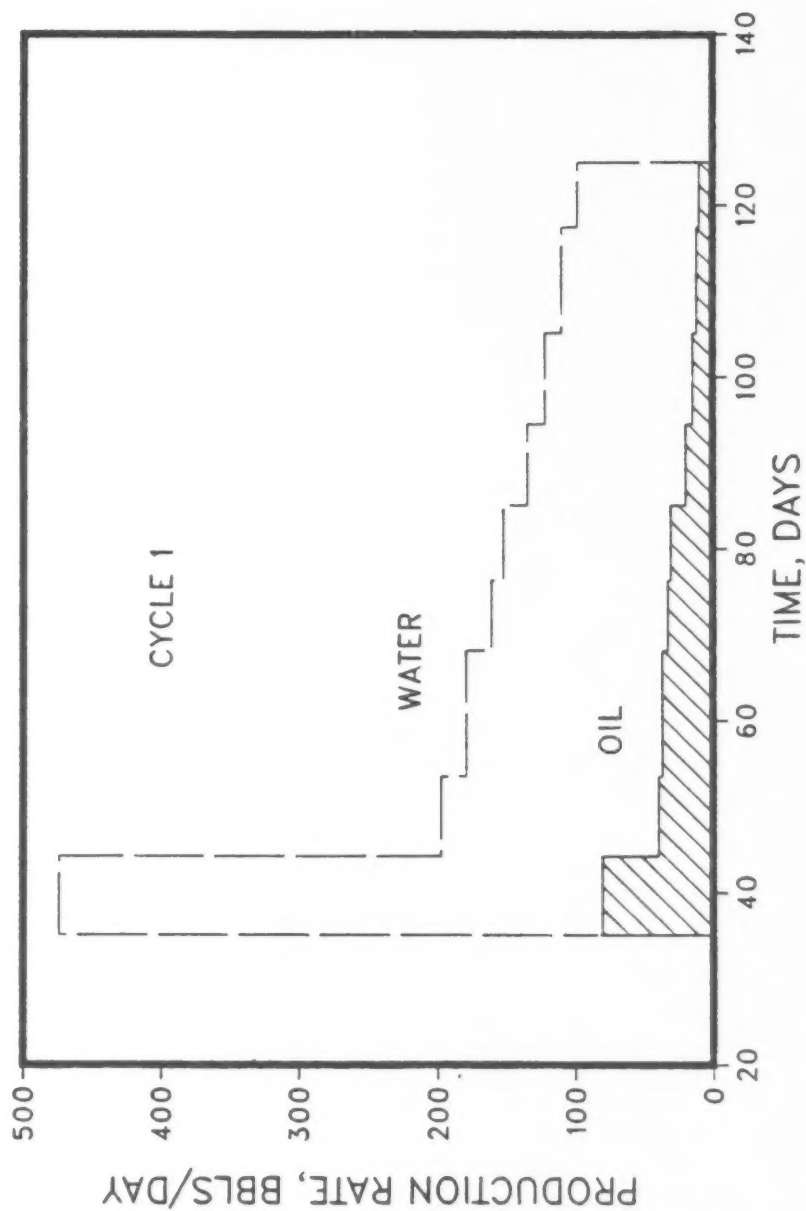


Figure 6.47 Production History for Aberfeldy Cyclic Run ABC1, No Bottom Water

CYCLIC STEAMING RUN ABC 1, ABERFELDY
NO BOTTOM WATER

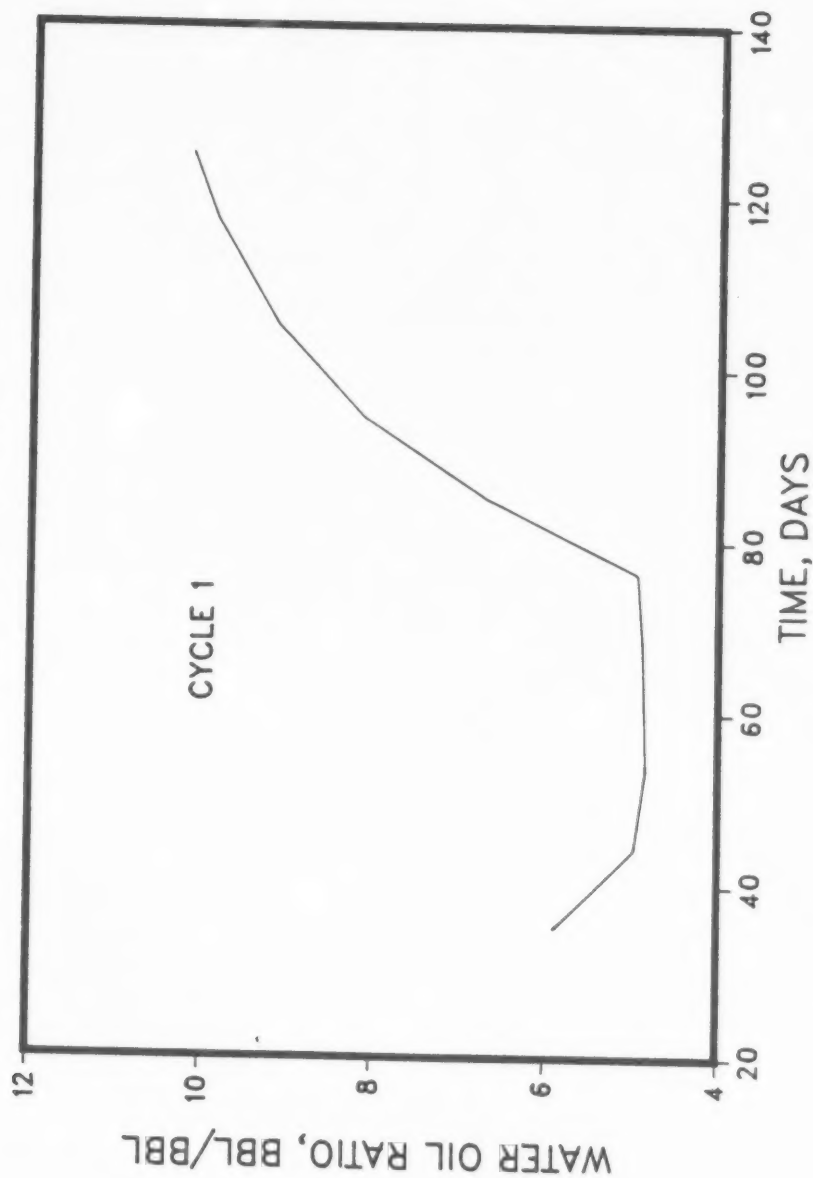


Figure 6.48 Water-Oil Ratio for Aberfeldy Cyclic Run ABC1, No Bottom Water

CYCLIC STEAMING RUN ABC 1, ABERFELDY
NO BOTTOM WATER

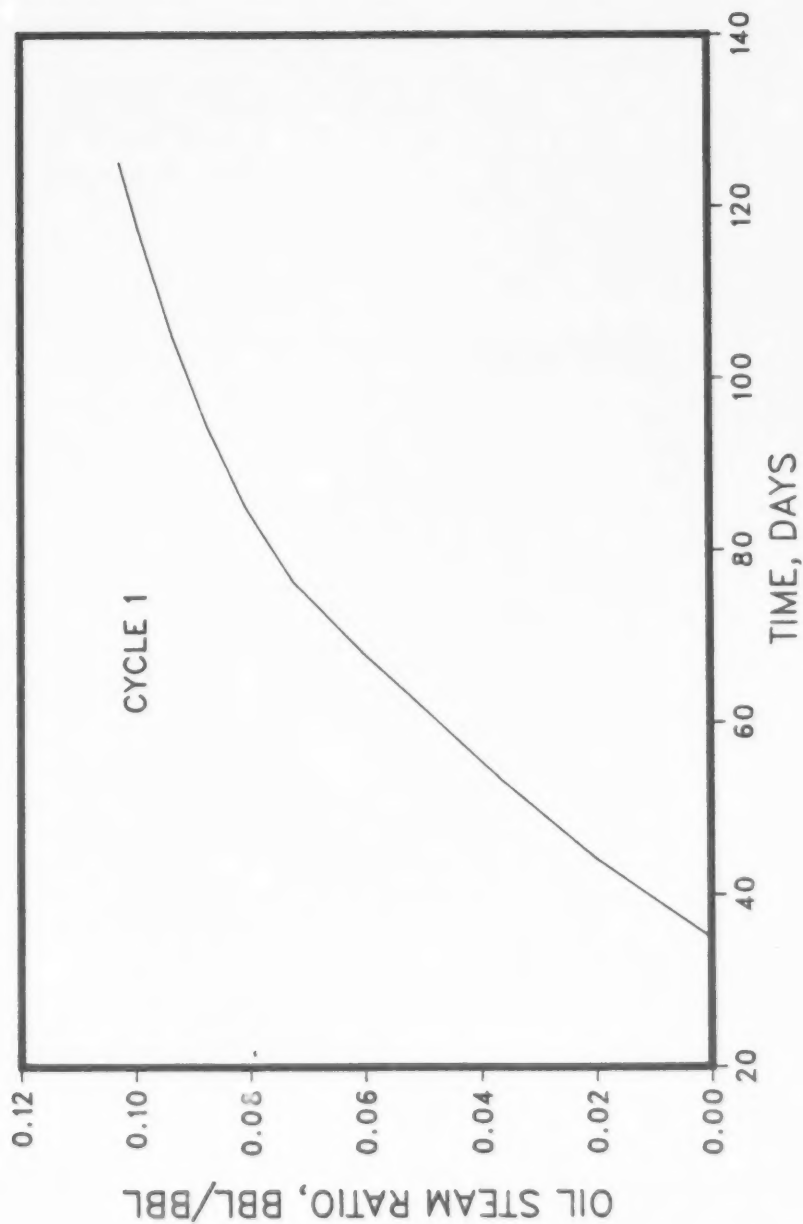


Figure 6.49 Oil-steam Ratio for Aberfeldy Cyclic Run ABC1, No Bottom Water

CYCLIC STEAMING RUN ABC 2, ABERFELDY
NO BOTTOM WATER

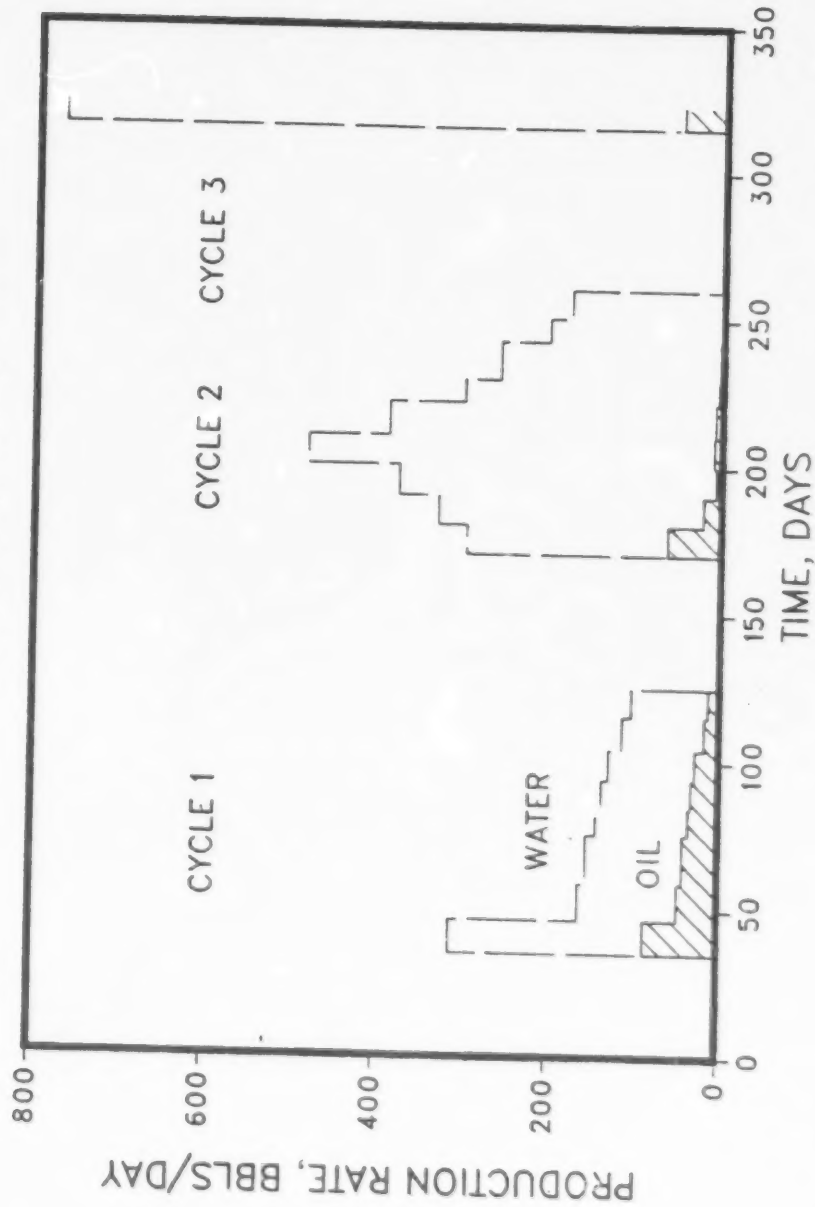


Figure 6.50 Production History for Aberfeldy Cyclic Run ABC2, No Bottom Water

CYCLIC STEAMING RUN ABC 2, ABERFELDY NO BOTTOM WATER

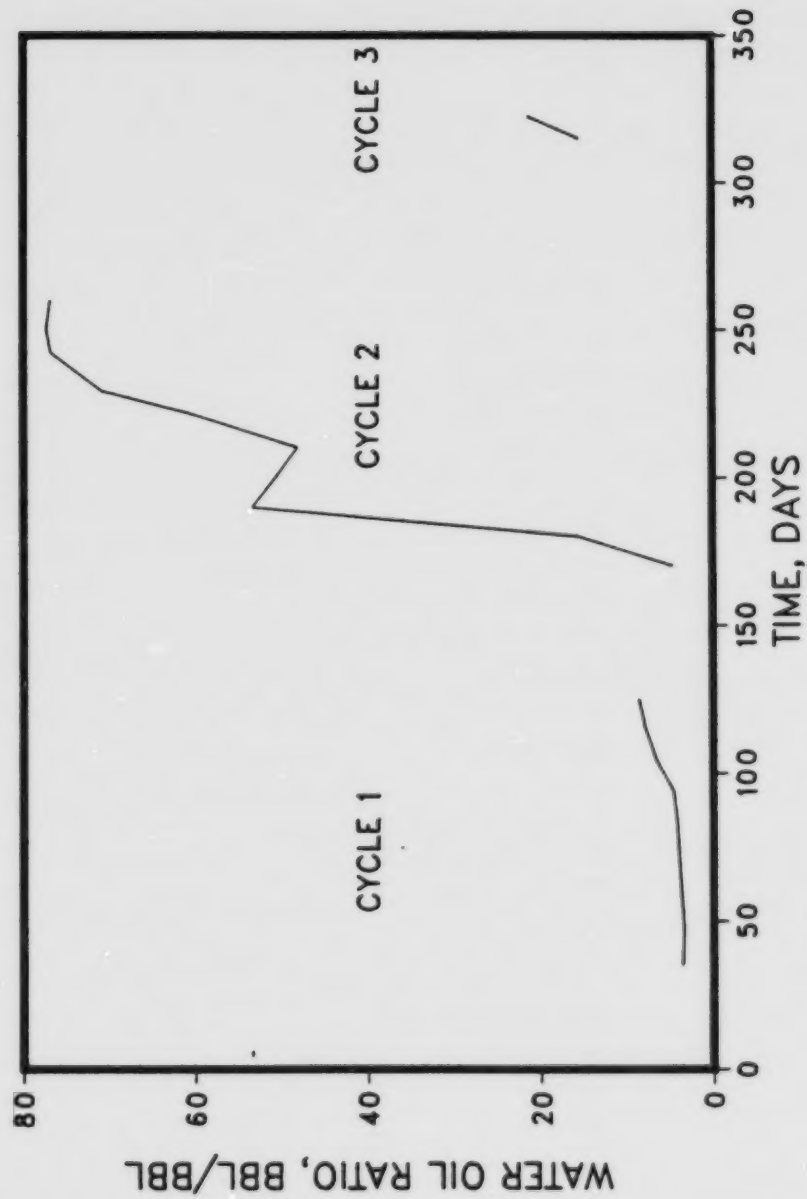


Figure 6.51 Water-Oil Ratio for Aberfeldy Cyclic Run ABC2, No Bottom Water

CYCLIC STEAMING RUN ABC 2, ABERFELDY NO BOTTOM WATER

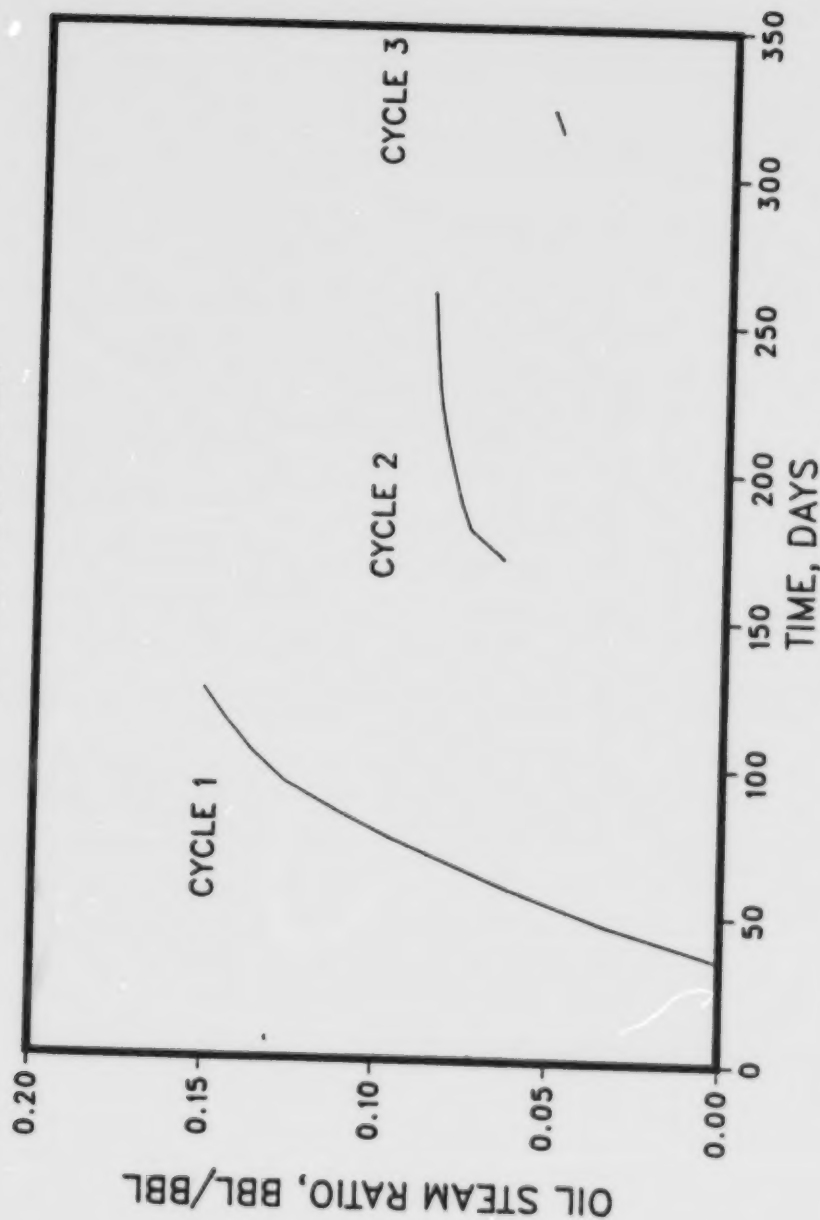


Figure 6.52 Oil-Steam Ratio for Aberfeldy Cyclic Run ABC2, No Bottom Water

CYCLIC STEAMING RUN ABC 3, ABERFELDY
NO BOTTOM WATER

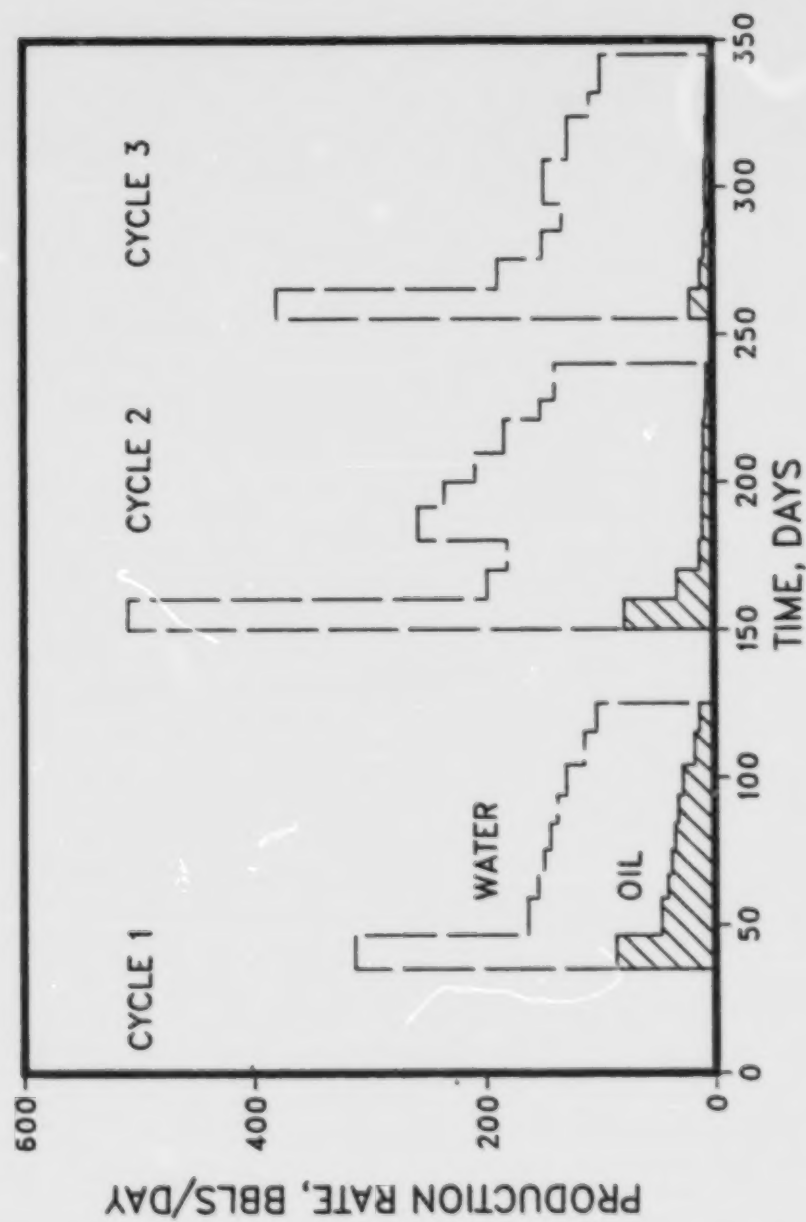


Figure 6.53 Production History for Aberfeldy Cyclic Run ABC3, No Bottom Water

CYCLIC STEAMING RUN ABC 3, ABERFELDY
NO BOTTOM WATER

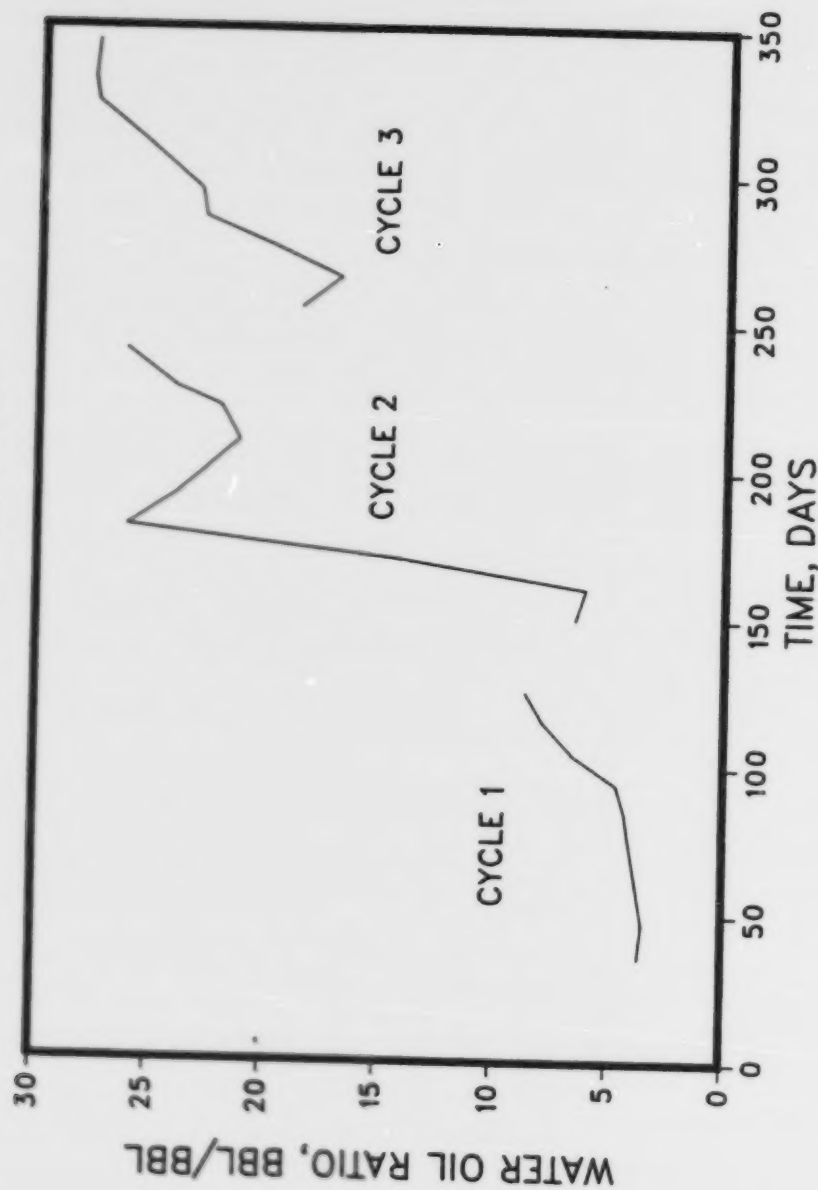


Figure 6.54 Water-Oil Ratio for Aberfeldy Cyclic Run ABC3, No Bottom Water

CYCLIC STEAMING RUN ABC 3, ABERFELDY
NO BOTTOM WATER

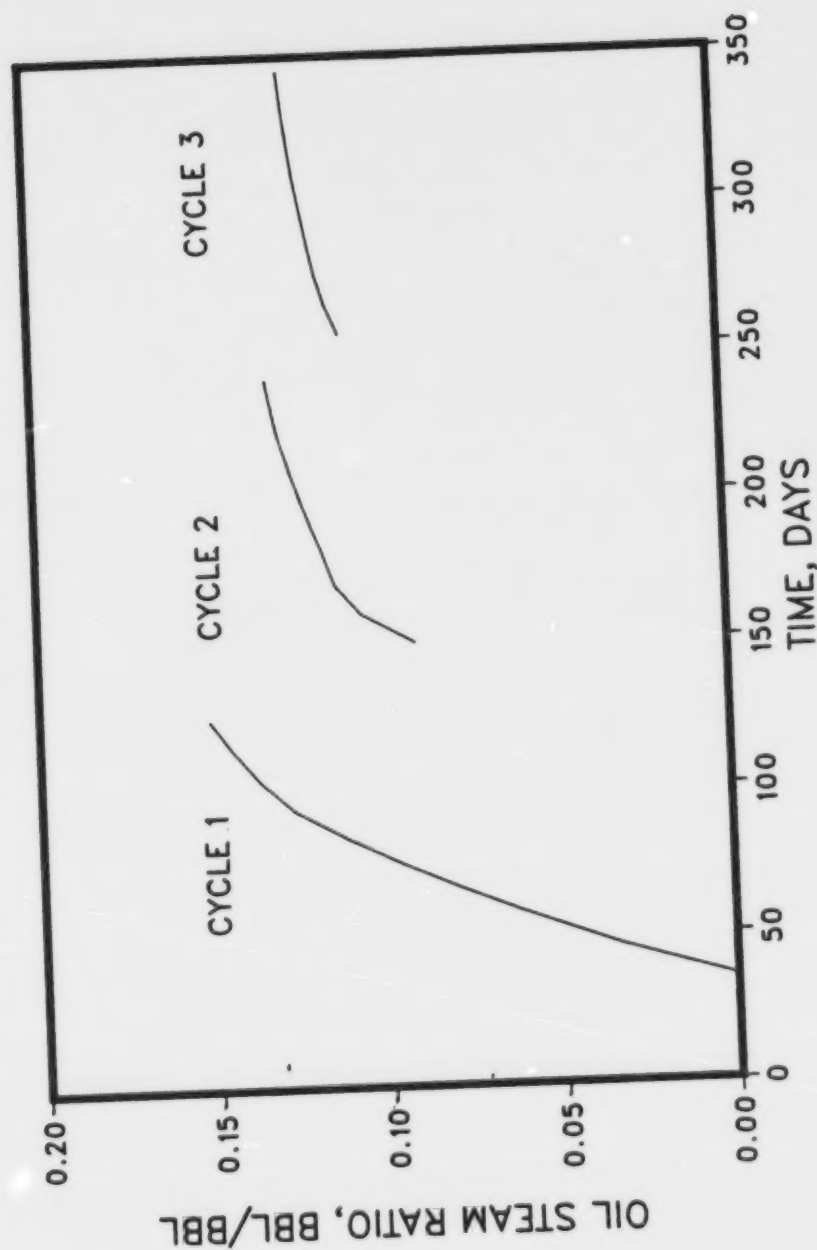


Figure 6.55 Oil-Steam Ratio for Aberfeldy Cyclic Run ABC3, No Bottom Water

CYCLIC STEAMING RUN ABC 4, ABERFELDY
NO BOTTOM WATER

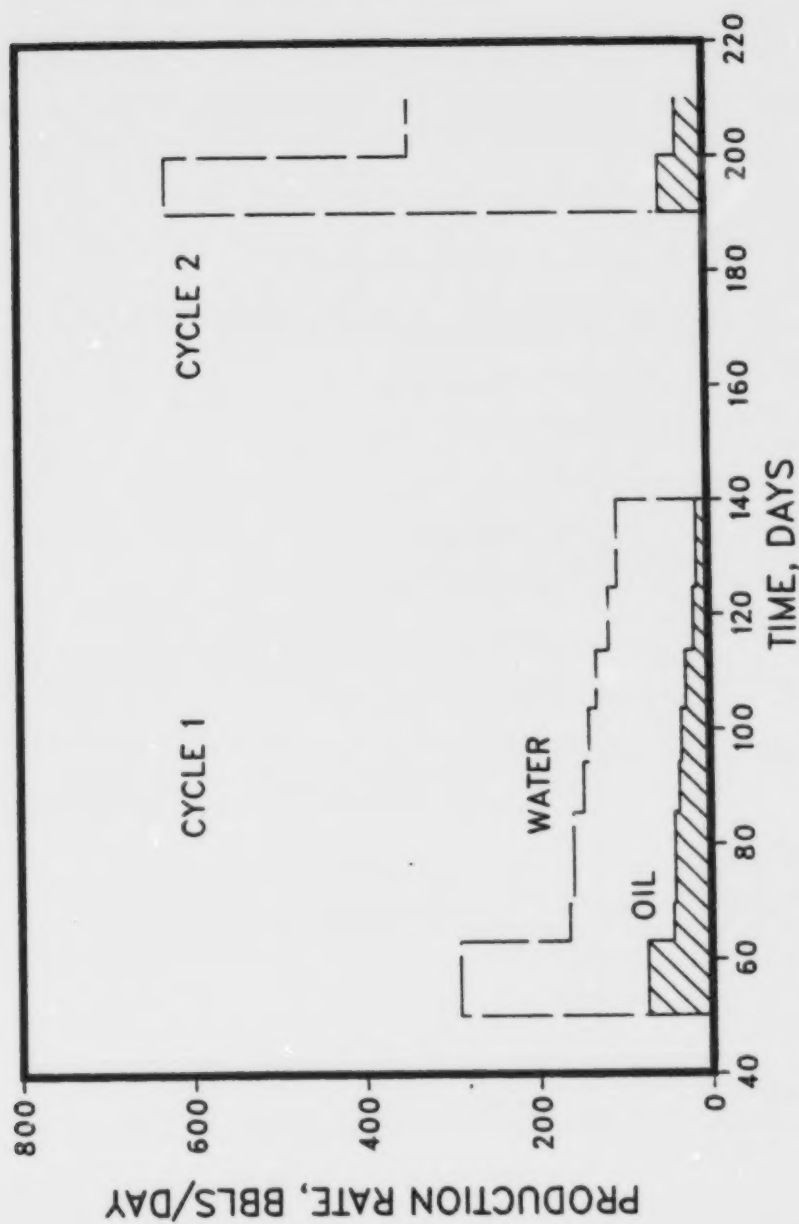


Figure 6.56 Production History for Aberfeldy Cyclic Run ABC4, No Bottom Water

CYCLIC STEAMING RUN ABC 4, ABERFELDY
NO BOTTOM WATER

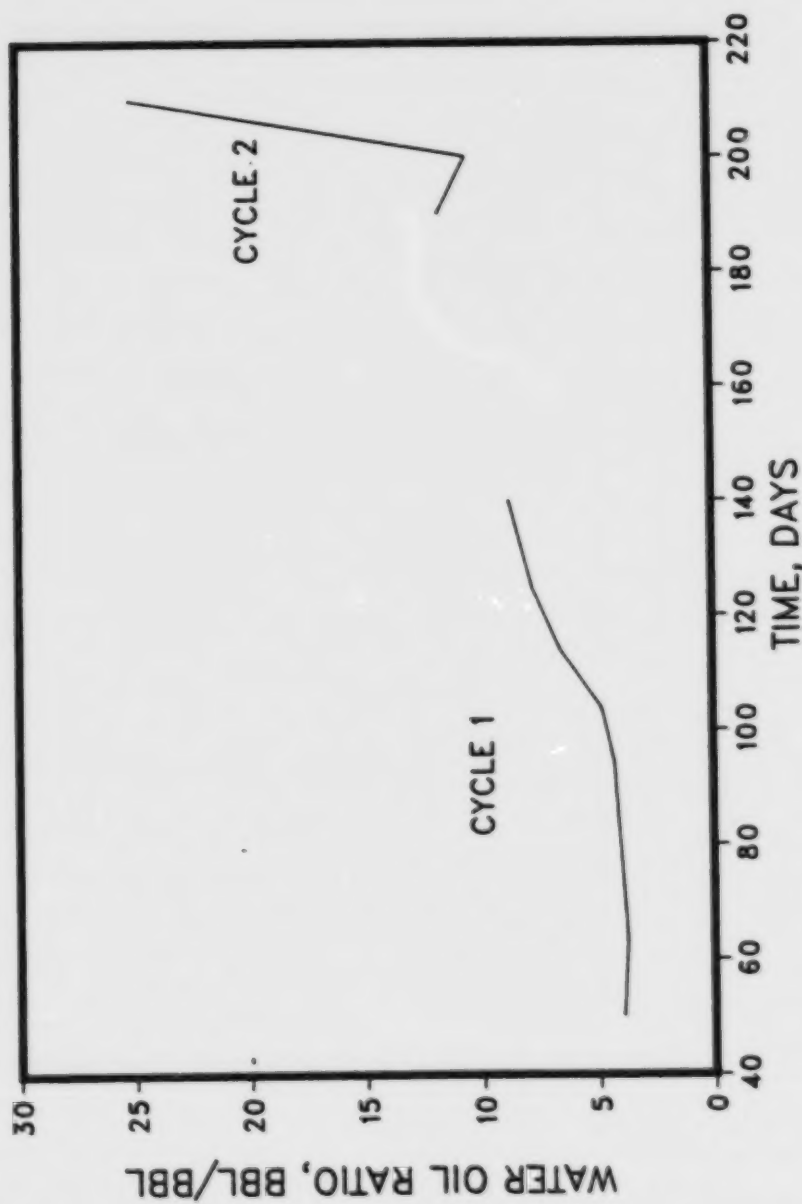


Figure 6.57 Water-Oil Ratio for Aberfeldy Cyclic Run ABC4, No Bottom Water

CYCLIC STEAMING RUN ABC 4, ABERFELDY NO BOTTOM WATER

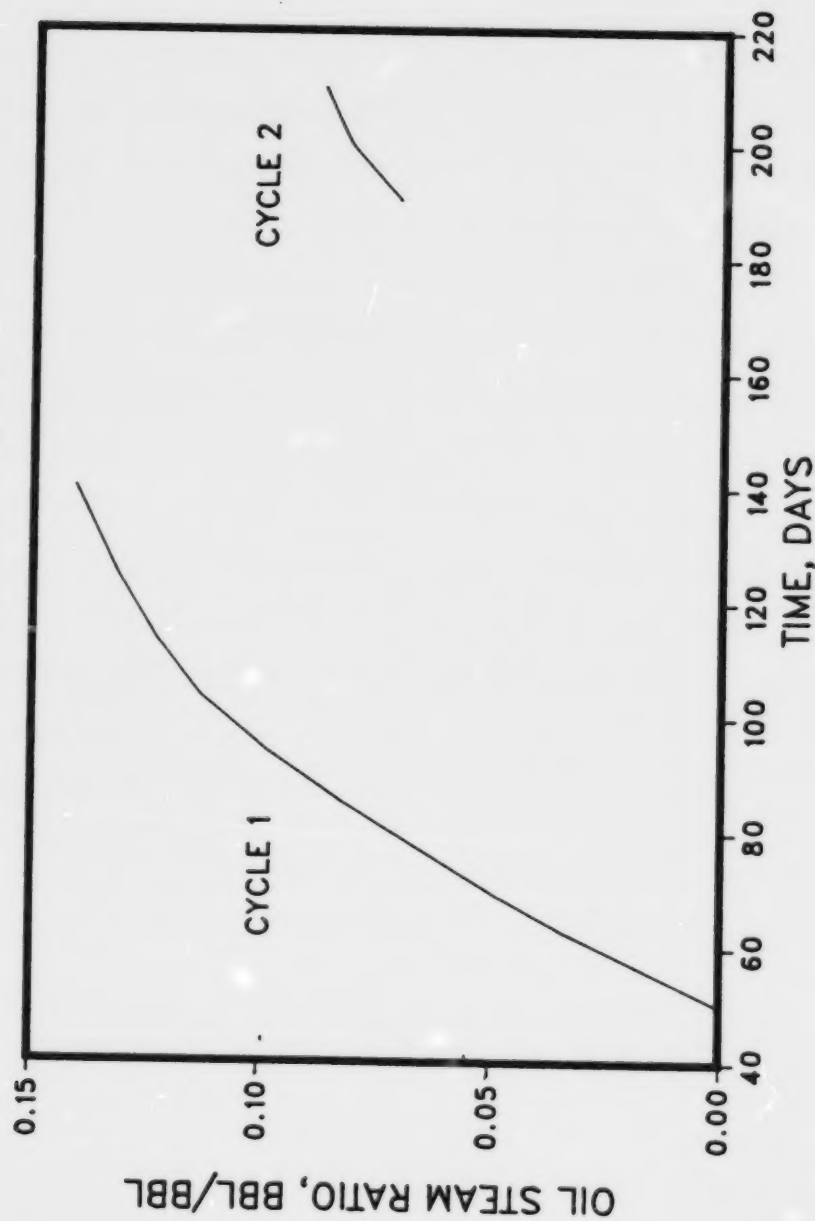


Figure 6.58 Oil-Steam Ratio for Aberfeldy Cyclic Run ABC4, No Bottom Water

runs correspond to the conditions given in the summary Table 6.3. The first run employs a constant steam slug size in each cycle, the second run employs increasing slugs from cycle to cycle, the third run utilizes decreasing slugs from cycle to cycle, and the fourth employs long soak times following steam injection. It is seen that the oil-steam ratio is highest - about 0.15 - in the first cycle. In subsequent cycles it drops because of water saturation buildup. This is expected because the formation thickness is small, so that gravity flow is limited. Furthermore, after the first cycle, the inflow of cold oil from the cooler parts of the formation is limited by the high oil viscosity. This is evidenced by the high WOR values in the first cycle, and in most cases in the second and third cycles. At the end of steam injection, the water saturation around the wellbore is very high, causing the very high WORs. The performance of Run ABC3 (Table C.16, Figs. 6.53-6.55) is most favourable, with steam slugs decreasing: 18, 12, and 6 MBbls, in the three cycles. The corresponding oil-steam ratios are 0.15, 0.13, and 0.12, respectively. In Run ABC2 (Table C.15, Figs. 6.50-6.52) the oil-steam ratios are lower, for the larger steam slugs used. A long soak time (20 days in Run ABC4) has a similar undesirable effect, leading to a drop in the oil-steam ratio, possibly due to cooling of the oil around the wellbore. On the basis of these limited results, it could be said that decreasing steam slugs in succeeding cycles are desirable, but the amount of decrease is a factor to be considered, and that long soak times cause a drop in the oil-steam ratio.

Effect of Bottom Water

The Aberfeldy runs discussed in the previous section were repeated for a bottom water zone (Runs ABC6, ABC8, ABC9). The results are summarized in Tables C.18 to C.22, and are plotted in Figs. 6.59 through 6.73. It is obvious that the performance throughout is poorer than in the absence of bottom water, Runs ABC1 to 4. The oil-steam ratio is seen to be nearly one-half, or less, of that in the absence of bottom water. The water-oil ratios are much higher - two to three times those in the absence of bottom water.

CYCLIC STEAMING RUN ABC 6, ABERFELDY BOTTOM WATER

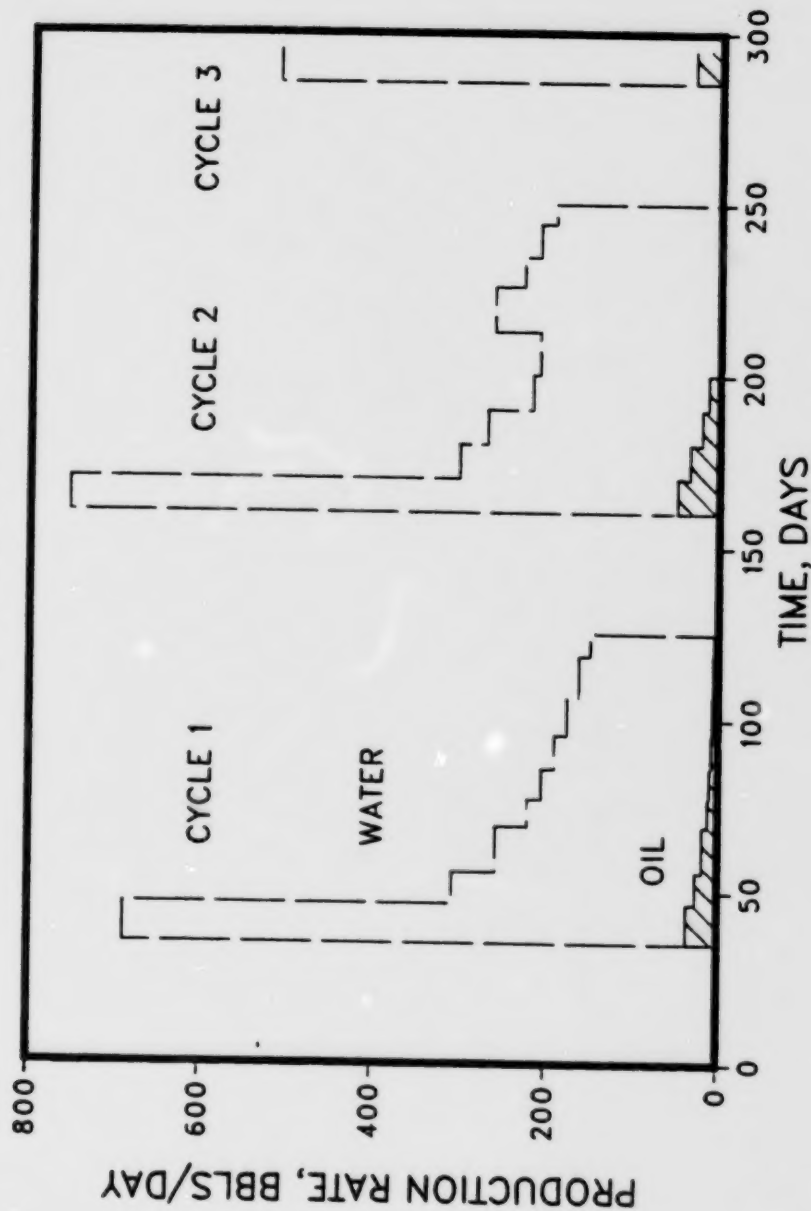


Figure 6.59 Production History for Aberfeldy Cyclic Run ABC6, Bottom Water

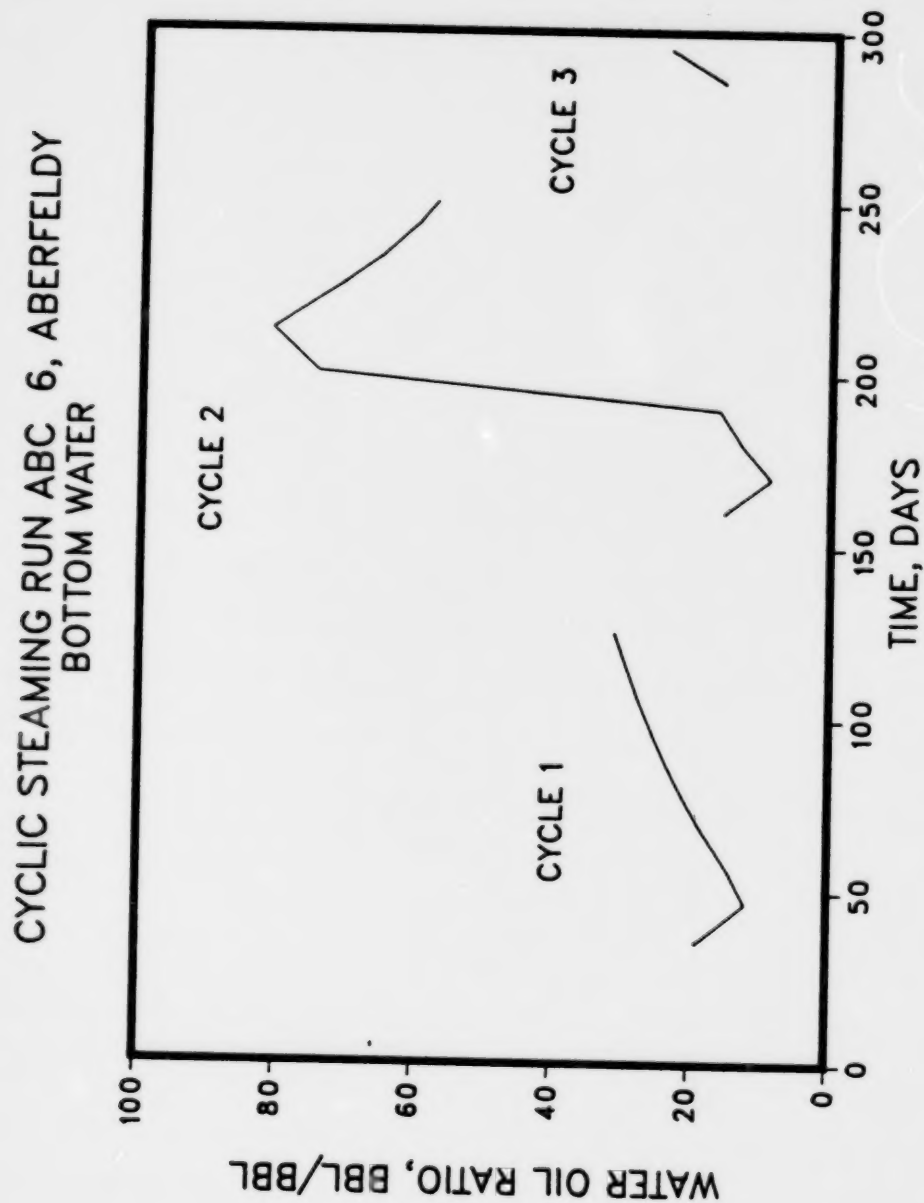


Figure 6.60 Water-Oil Ratio for Aberfeldy Cyclic Run ABC6, Bottom Water

CYCLIC STEAMING RUN ABC 6, ABERFELDY
BOTTOM WATER

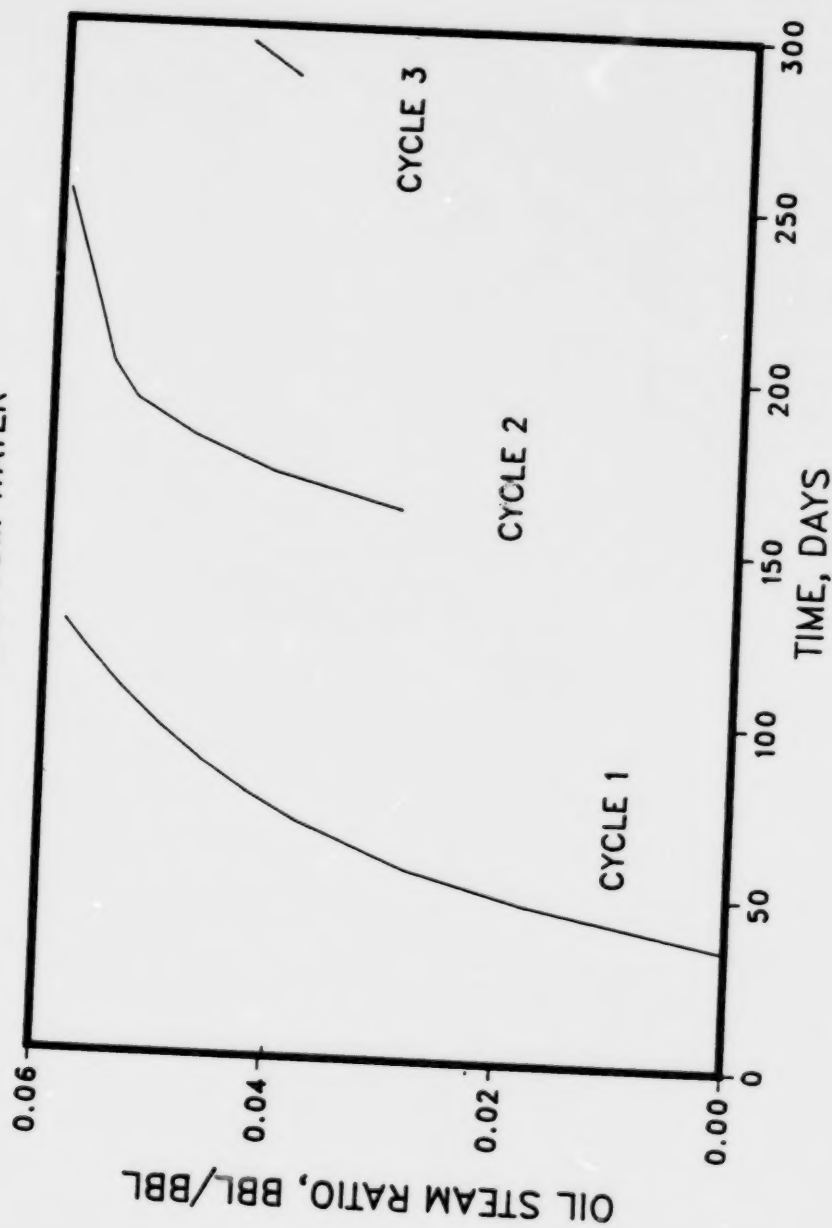


Figure 6.61 Oil-Steam Ratio for Aberfeldy Cyclic Run ABC6, Bottom Water

CYCLIC STEAMING RUN ABC 8, ABERFELDY
BOTTOM WATER

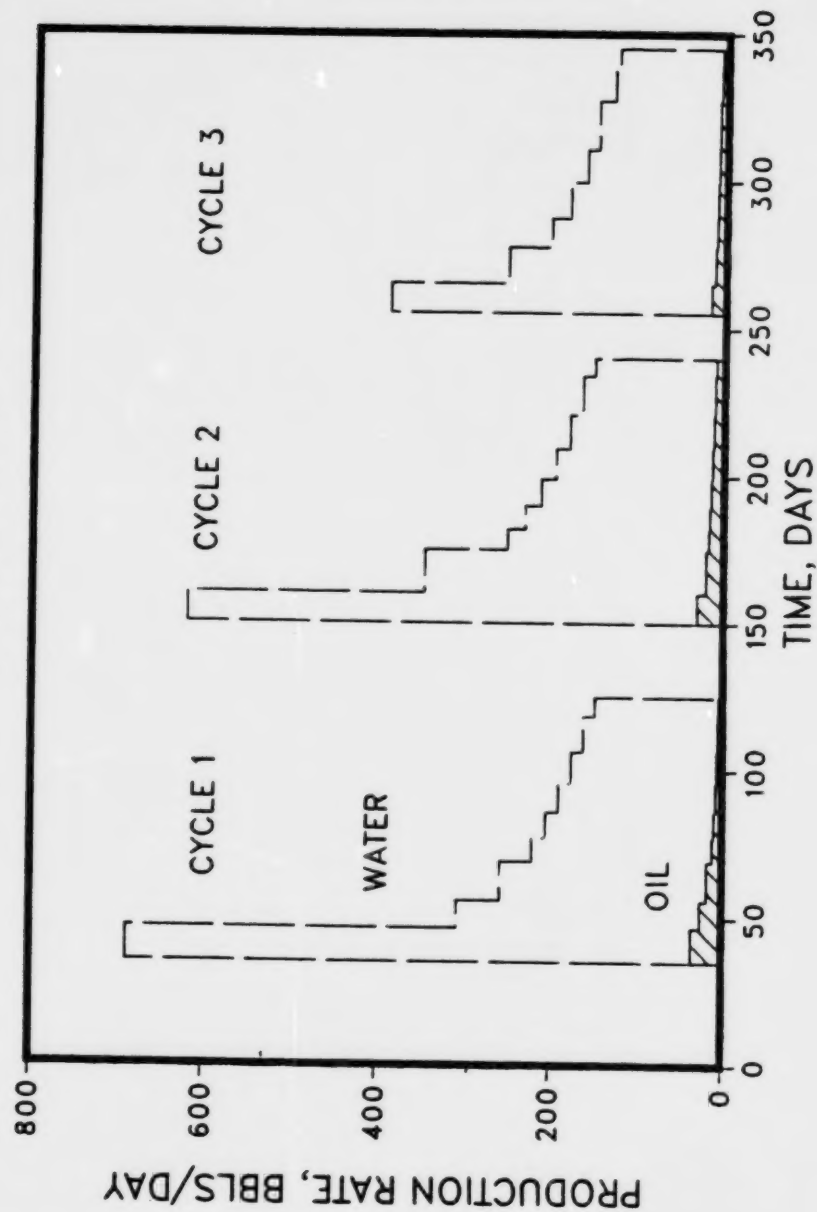


Figure 6.62 Production History for Aberfeldy Cyclic Run ABC8, Bottom Water

CYCLIC STEAMING RUN ABC 8, ABERFELDY
BOTTOM WATER

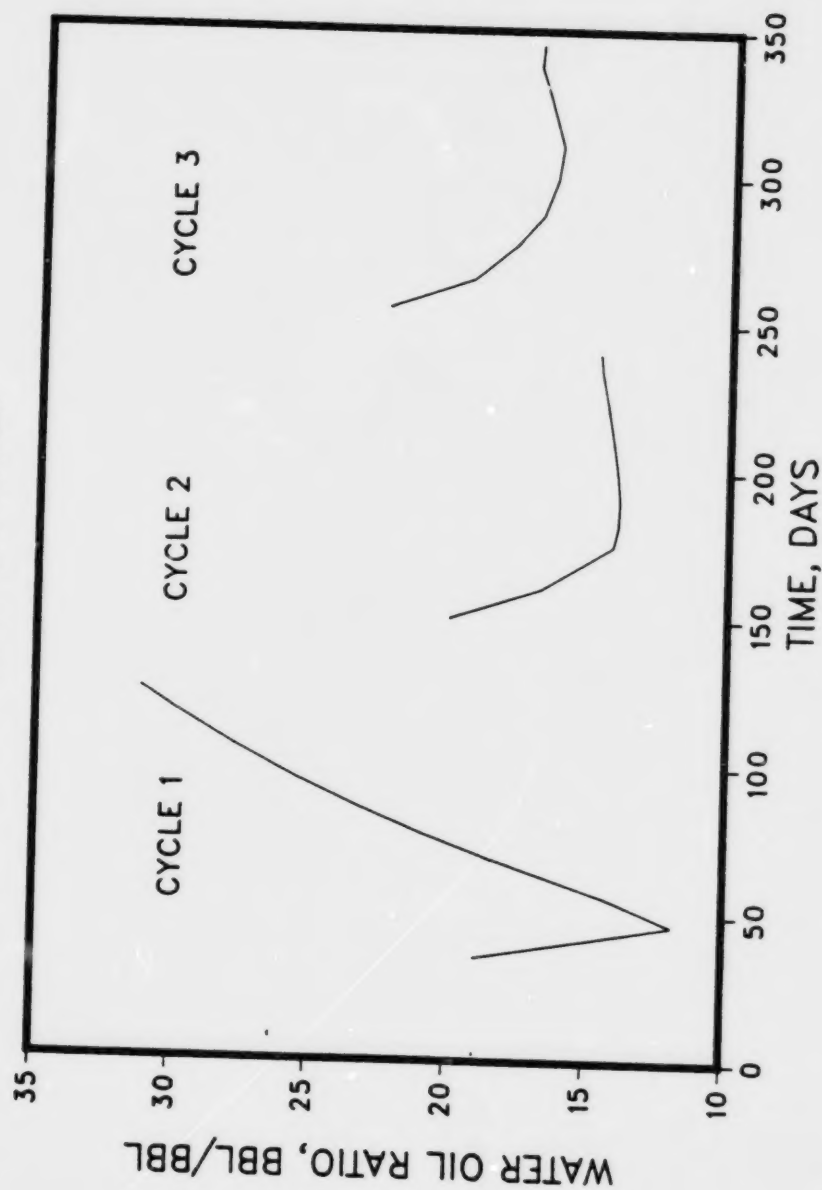


Figure 6.63 Water-Oil Ratio for Aberfeldy Cyclic Run ABC8, Bottom Water

CYCLIC STEAMING RUN ABC 8, ABERFELDY
BOTTOM WATER

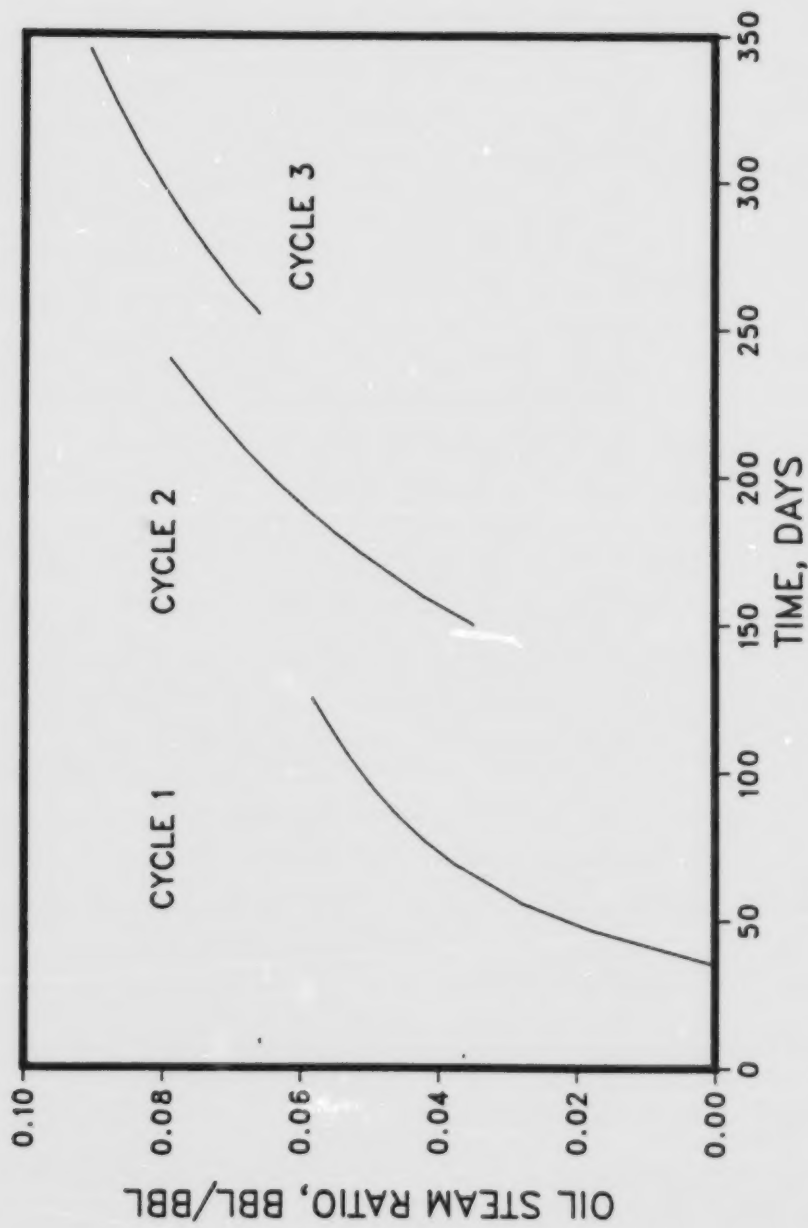


Figure 6.64 Oil-Steam Ratio for Aberfeldy Cyclic Run ABC8, Bottom Water

CYCLIC STEAMING RUN ABC 9, ABERFELDY
BOTTOM WATER

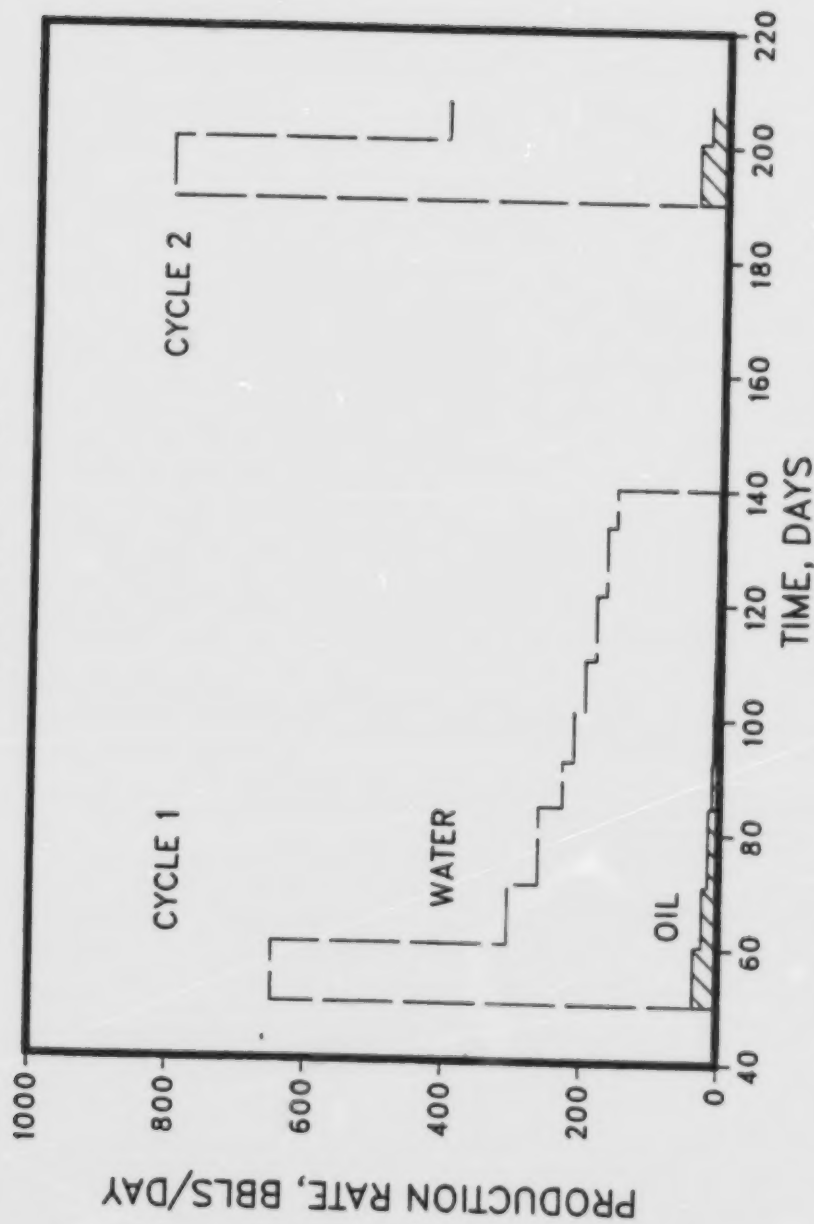


Figure 6.65 Production History for Aberfeldy Cyclic Run ABC9, Bottom Water

CYCLIC STEAMING RUN ABC 9, ABERFELDY BOTTOM WATER

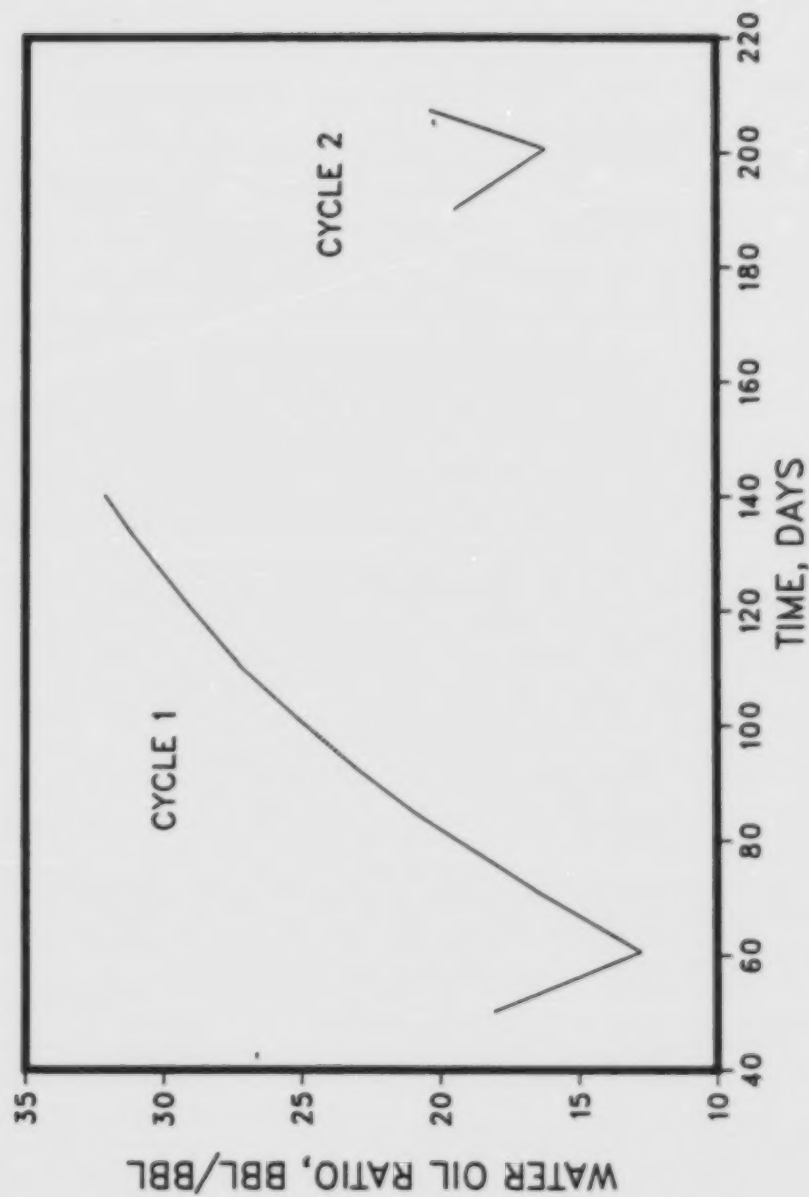


Figure 6.66 Water-Oil Ratio for Aberfeldy Cyclic Run ABC9, Bottom Water

CYCLIC STEAMING RUN ABC 9, ABERFELDY BOTTOM WATER

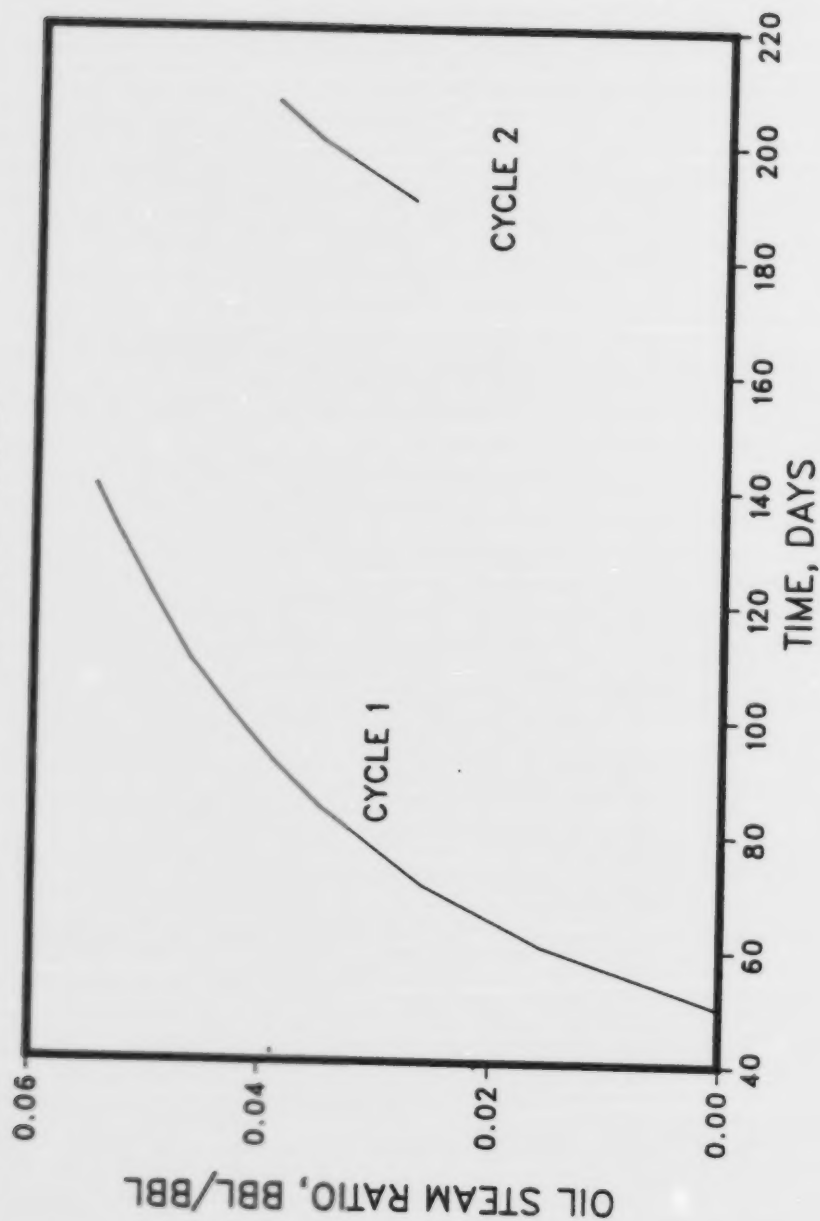


Figure 6.67 Oil-Steam Ratio for Aberfeldy Cyclic Run ABC9, Bottom Water

CYCLIC STEAMING RUN ABC 11, ABERFELDY
BOTTOM WATER

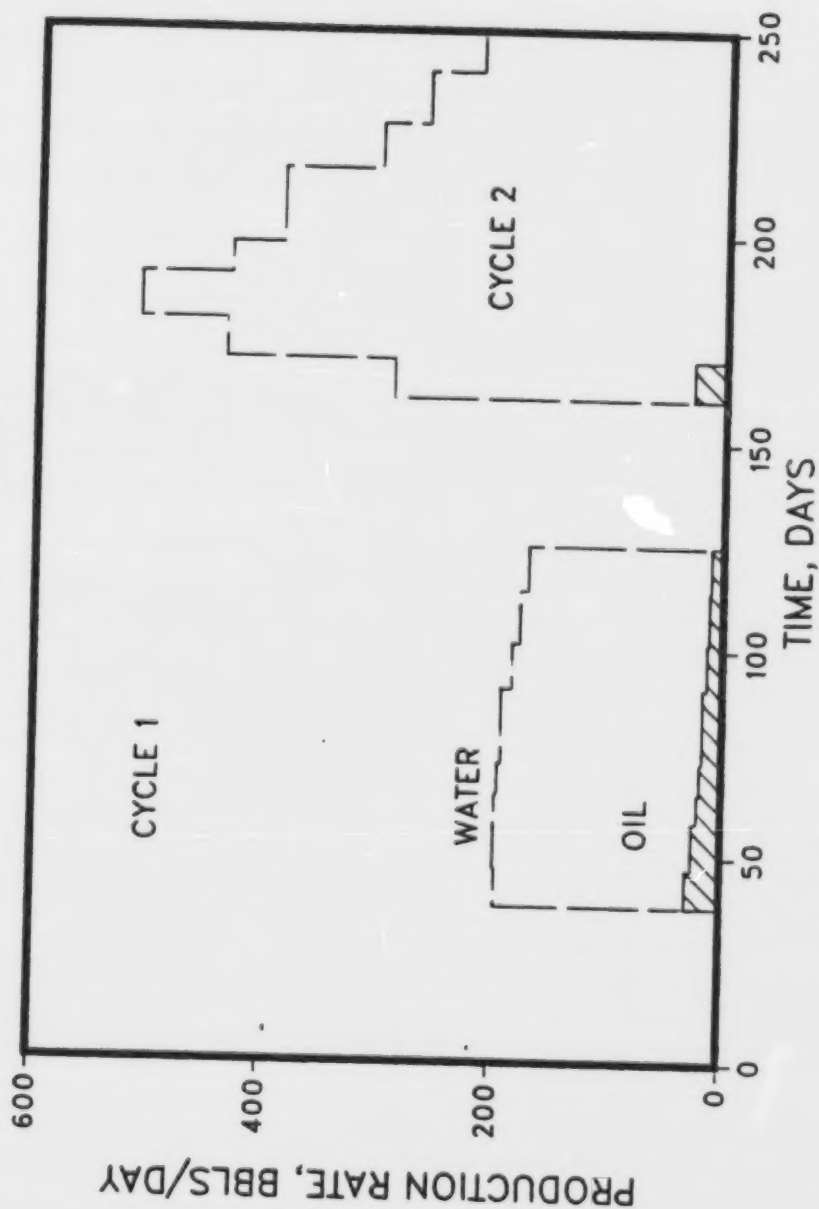


Figure 6.68 Production History for Aberfeldy Cyclic Run ABC11, Bottom Water

CYCLIC STEAMING RUN ABC 11, ABERFELDY
BOTTOM WATER

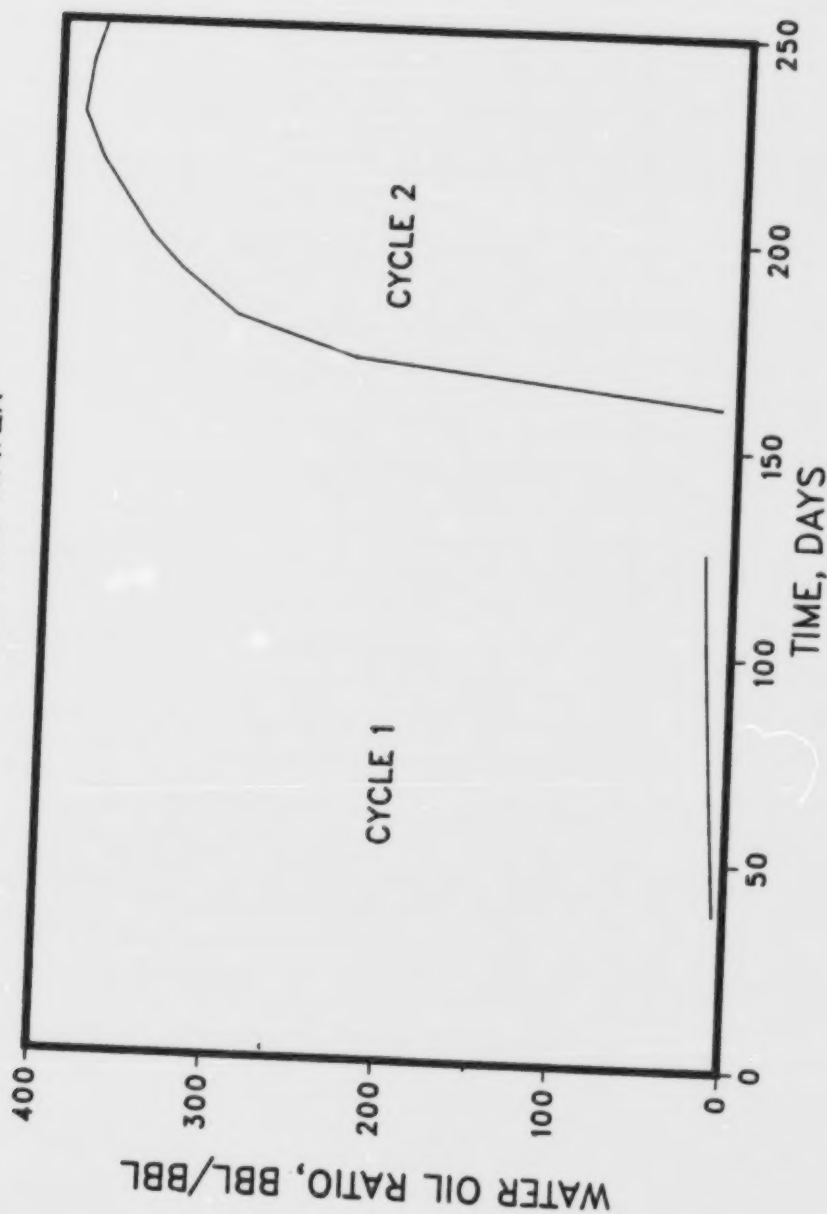


Figure 6.69 Water-Oil Ratio for Aberfeldy Cyclic Run ABC11, Bottom Water

CYCLIC STEAMING RUN ABC 11, ABERFELDY
BOTTOM WATER

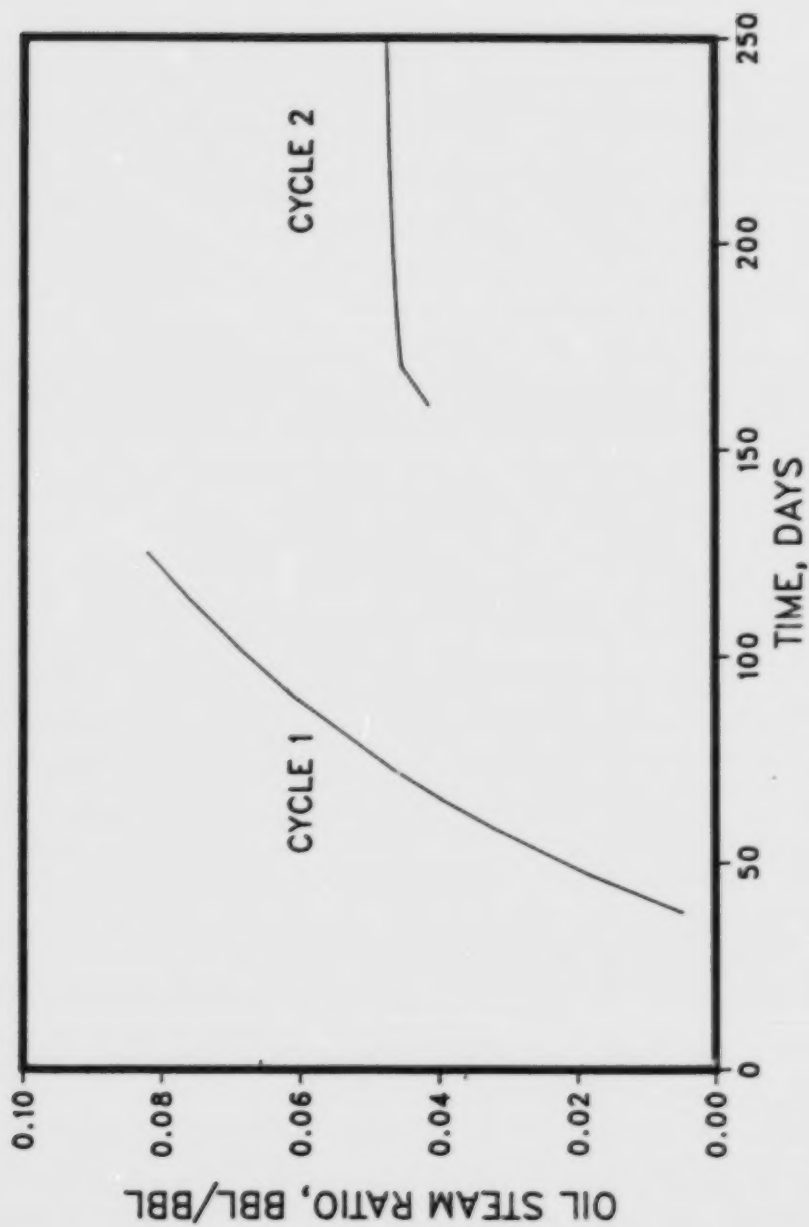


Figure 6.70 Oil-Steam Ratio for Aberfeldy Cyclic Run ABC11, Bottom Water

CYCLIC STEAMING RUN ABC 17, ABERFELDY BOTTOM WATER

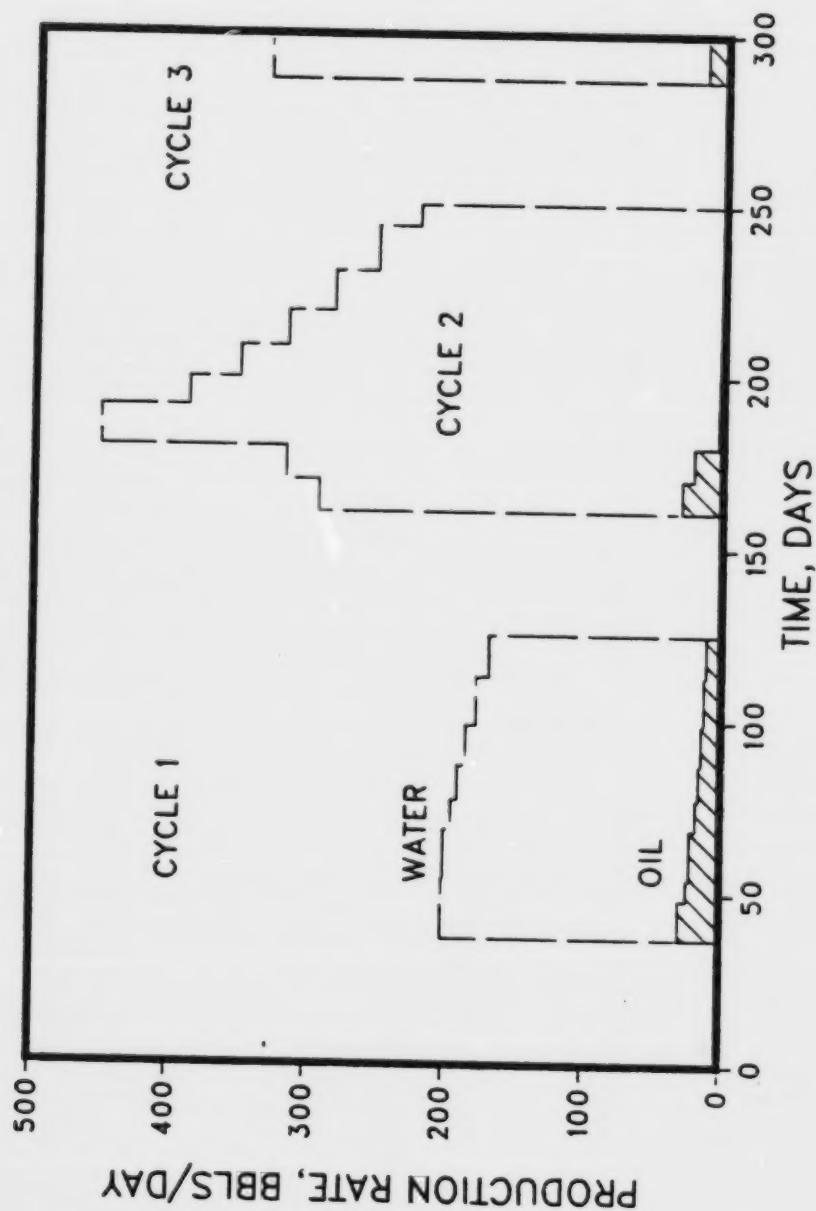


Figure 6.71 Production History for Aberfeldy Cyclic Run ABC17, Bottom Water

CYCLIC STEAMING RUN ABC 17, ABERFELDY
BOTTOM WATER

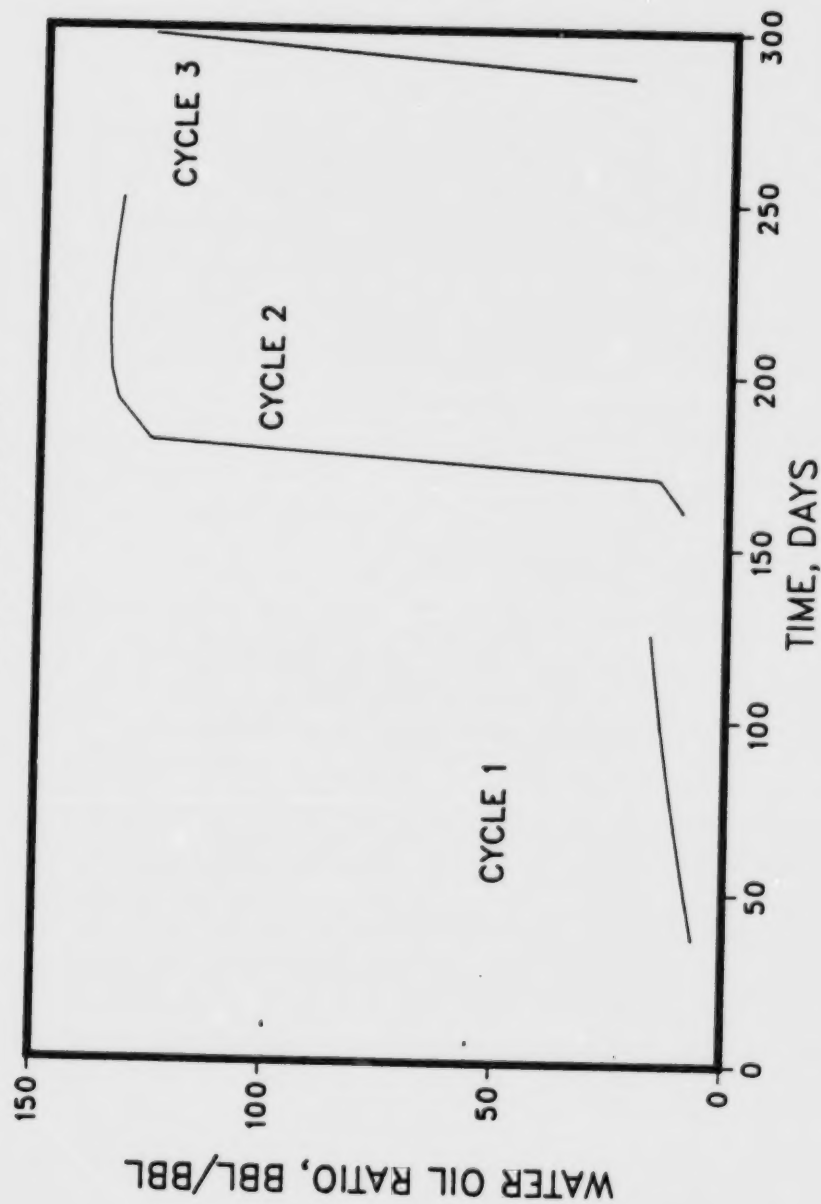


Figure 6.72 Water-Oil Ratio for Aberfeldy Cyclic Run ABC17, Bottom Water

CYCLIC STEAMING RUN ABC 17, ABERFELDY
BOTTOM WATER

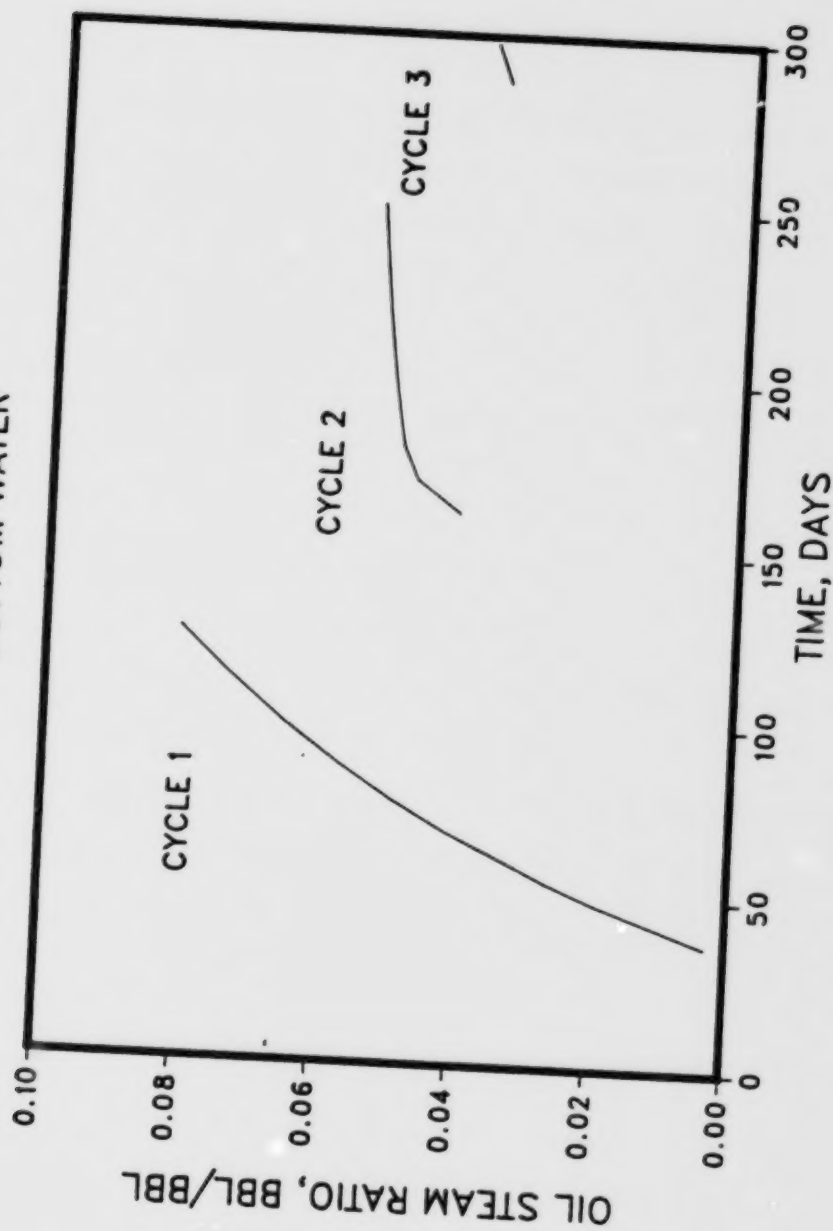


Figure 6.73 Oil-Steam Ratio for Aberfeldy Cyclic Run ABC17, Bottom Water

In Run ABC11, in the second cycle (Table C.21), the WORs are 200-400 (see Fig. 6.69, which shows the contrast between the first and second cycle WORs). This is mainly due to a much larger water zone in this case. At the same time, the steam slug used in the second cycle is twice as large as for the first cycle, i.e. 36000 bls, which also would increase water production rates. This trend is also evident from the performances of Runs ABC6 and ABC8 (Tables C.18 and 19, Figs. 6.60 and 6.63), where the WOR in the second cycle is higher when a larger volume of steam is injected. It is difficult to explain why the WOR in the second cycle of Run ABC8 is lower than that in the first cycle of the same run, although considerably more steam was injected in the second cycle. It is the result of complex interaction of the limited bottom water, conductive heating, and relative mobility/temperature relationships. The oil-steam ratio in the third cycle shows an improvement, because the conductive heating from the water layer to the oil layer above is starting to take effect.

Based upon the above, it may be said, that generally speaking, bottom water is undesirable in cyclic steaming, particularly when the bottom water thickness is large. Increasing steam slugs from cycle to cycle may have limited benefits, but it is more likely to give poorer performance than a constant slug. In fact, there may be some merit in reducing the steam slug size when bottom water is present. In all cases simulated, the oil-steam ratio was well below the minimum acceptable value of 0.10.

Cyclic Steam Simulations: Cold Lake

Several cyclic steam stimulation simulations were carried out for the Cold Lake Clearwater formation, three of which (Runs CLC1A, CLC6A, and CLC11A) are summarized in Tables C.23 to C.25, and in Figs. 6.74 through 6.82. The first run is for the no-bottom water case, while in the other two runs, bottom water thicknesses one-tenth and equal to the oil zone thicknesses are assumed.

CYCLIC RUN CLC1A, COLD LAKE NO BOTTOM WATER

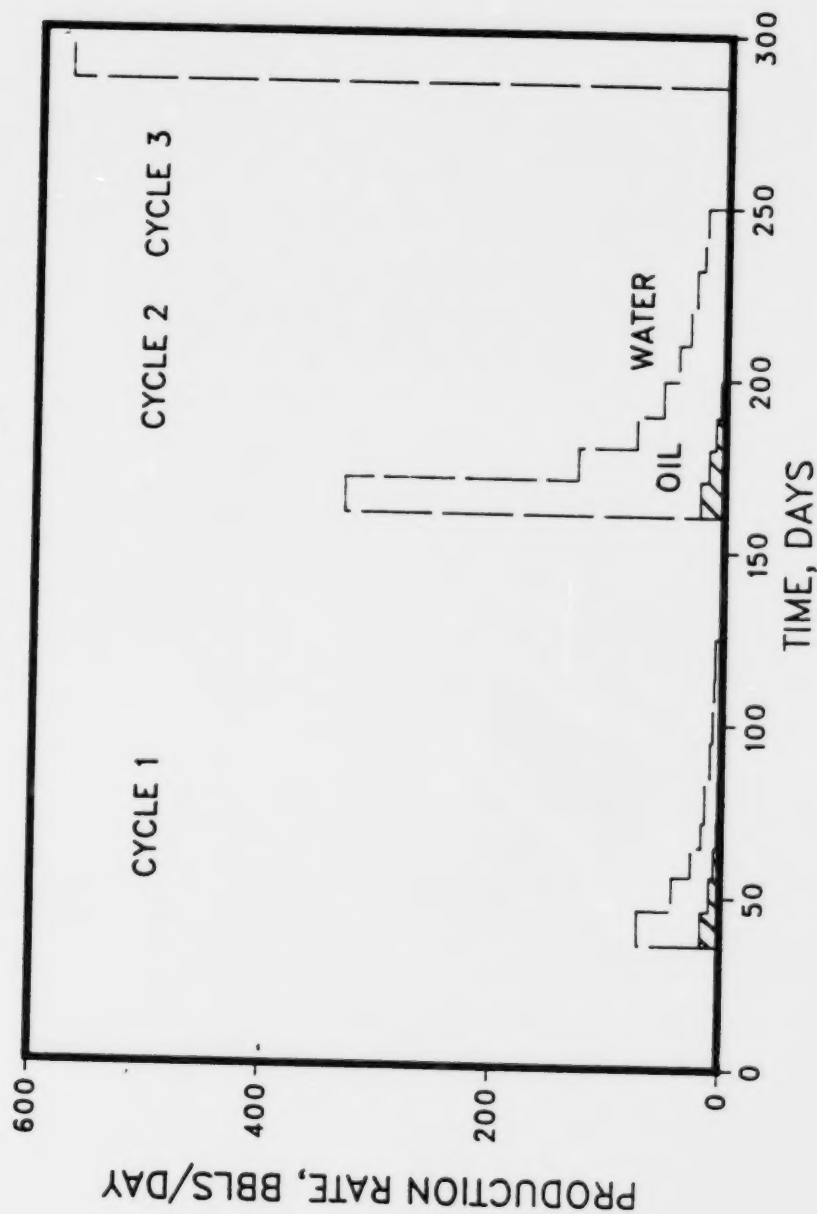


Figure 6.74 Production History for Cold Lake Cyclic Run CLC1A, No Bottom Water

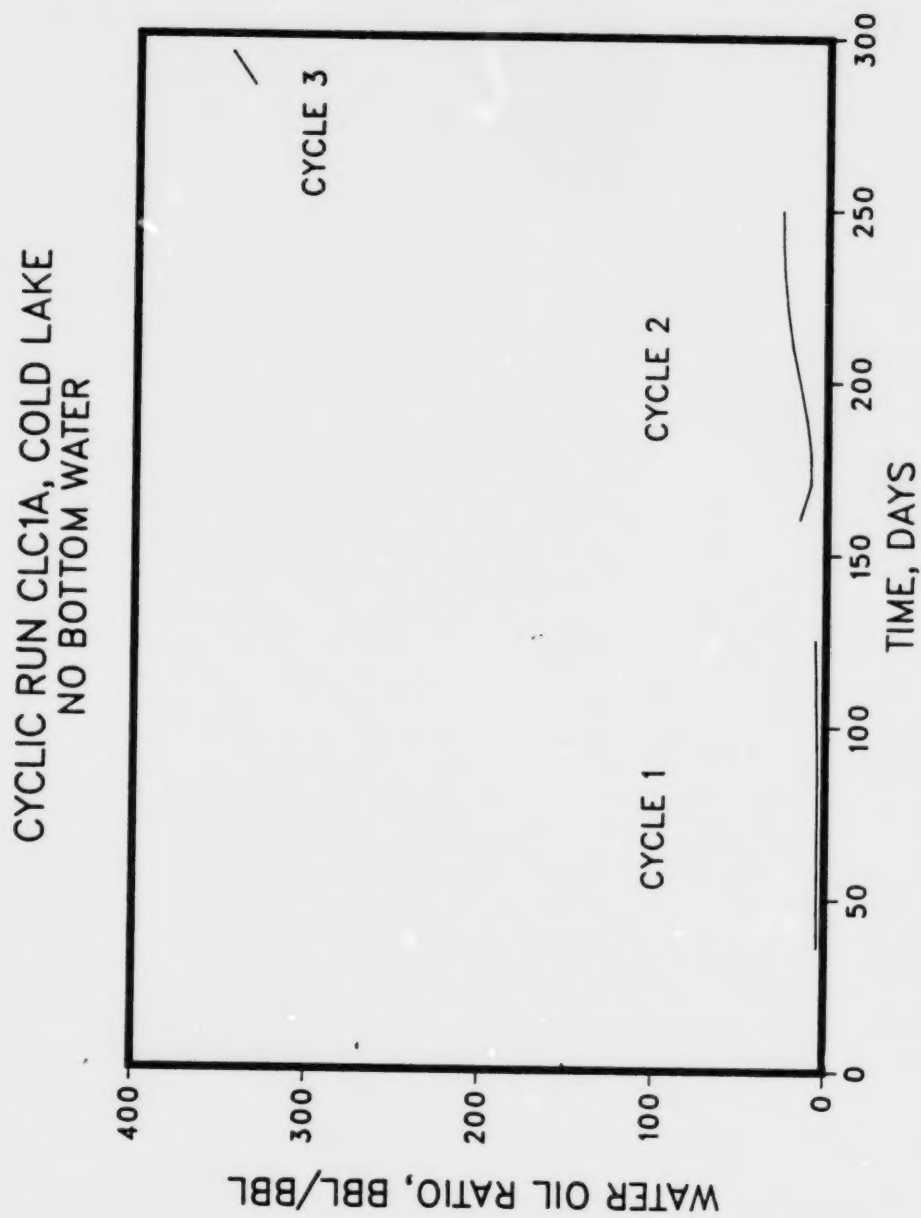


Figure 6.75 Water-Oil Ratio for Cold Lake Cyclic Run CLC1A, No Bottom Water

CYCLIC RUN CLC1A, COLD LAKE
NO BOTTOM WATER

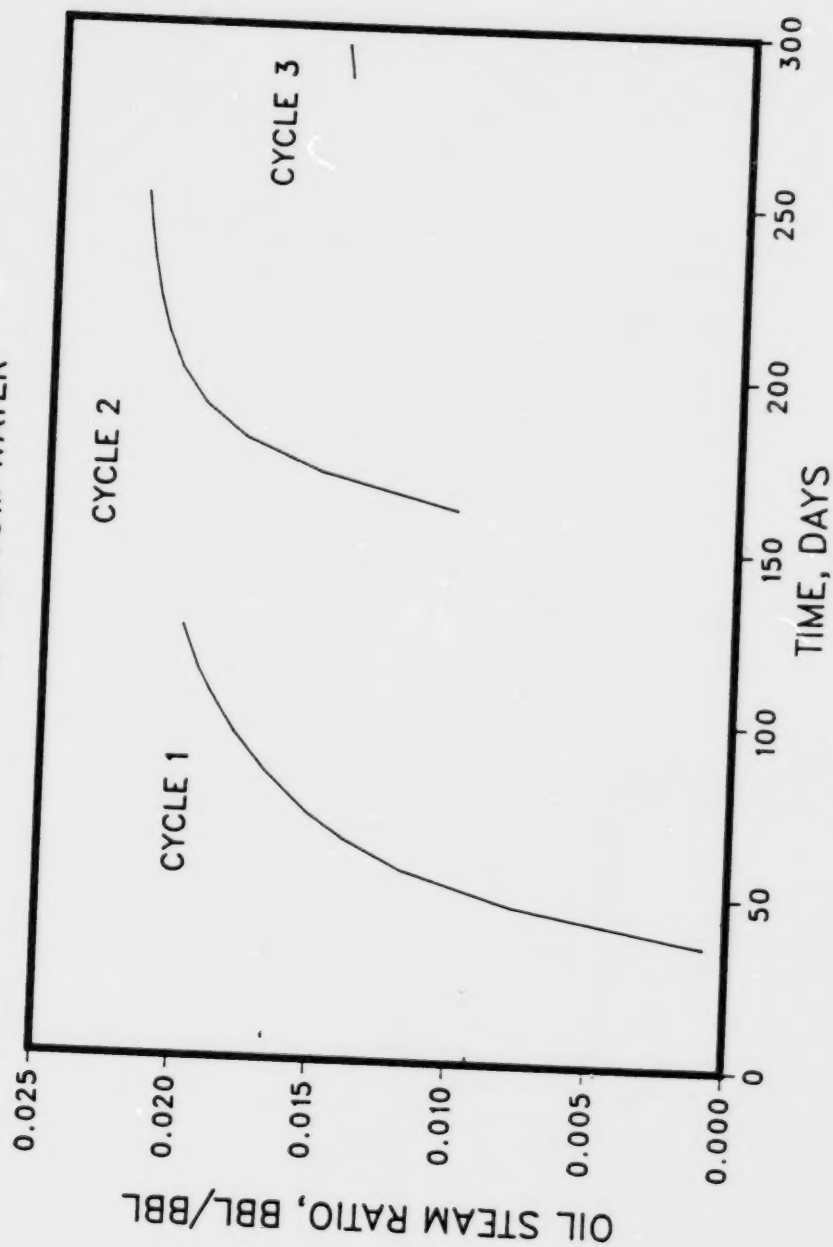


Figure 6.76 Oil-Steam Ratio for Cold Lake Cyclic Run CLC1A, No Bottom Water

CYCLIC RUN CLC6A, COLD LAKE
BOTTOM WATER 36FT/36FT

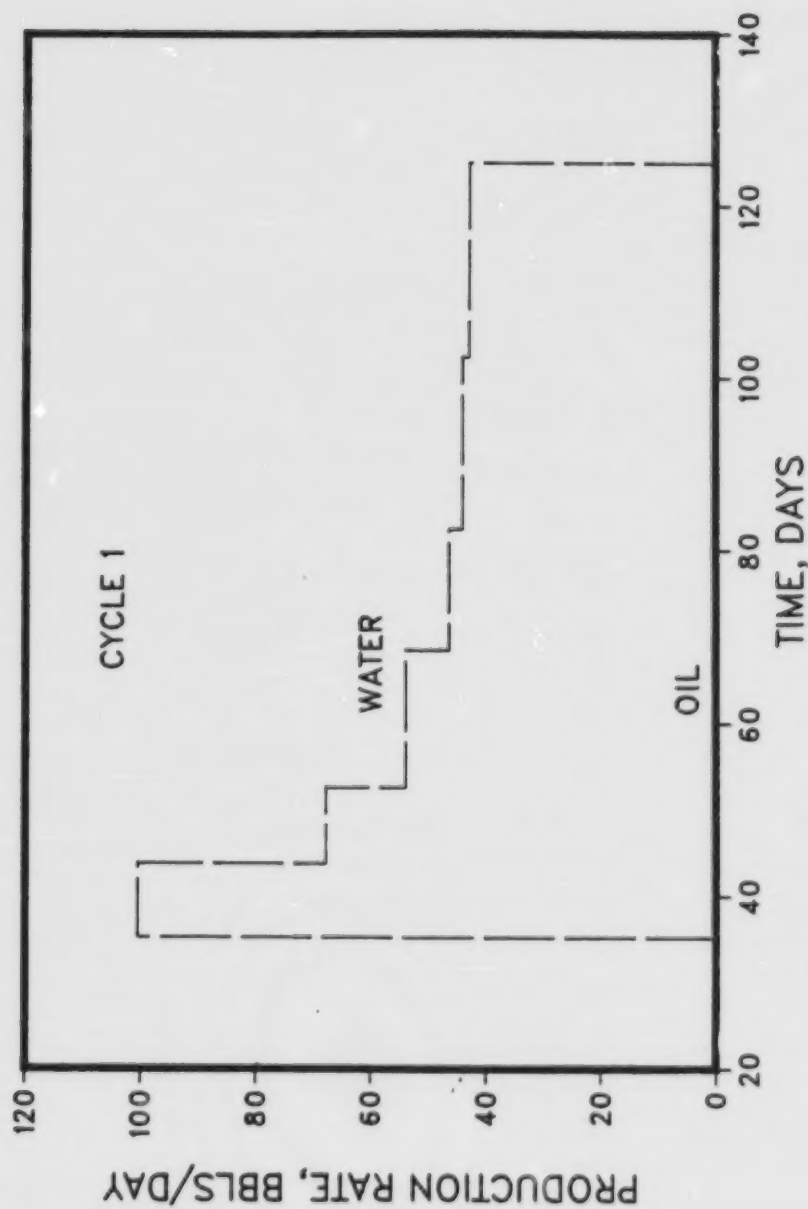


Figure 6.77 Production History for Cold Lake Cyclic Run CLC6A, Bottom Water

CYCLIC RUN CLC6A, COLD LAKE BOTTOM WATER 36FT/36FT

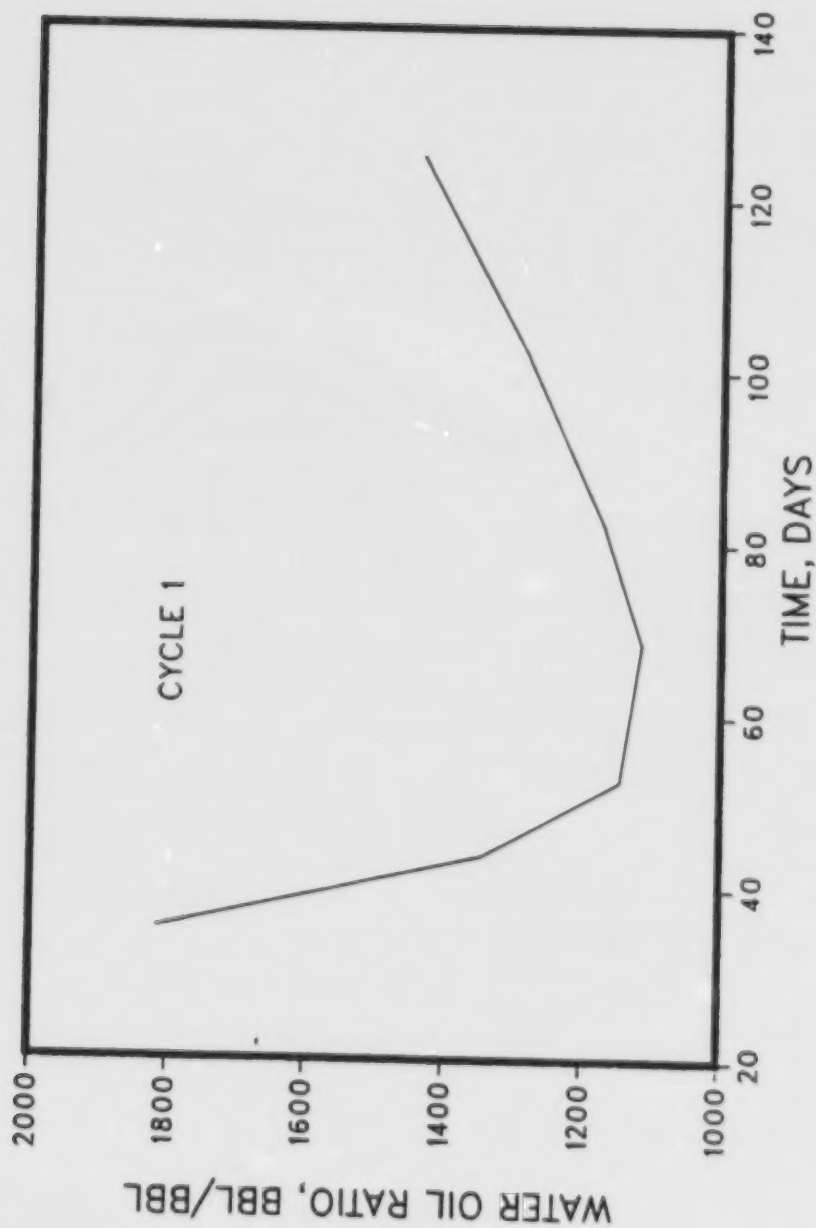


Figure 6.78 Water-Oil Ratio for Cold Lake Cyclic Run CLC6A, Bottom Water

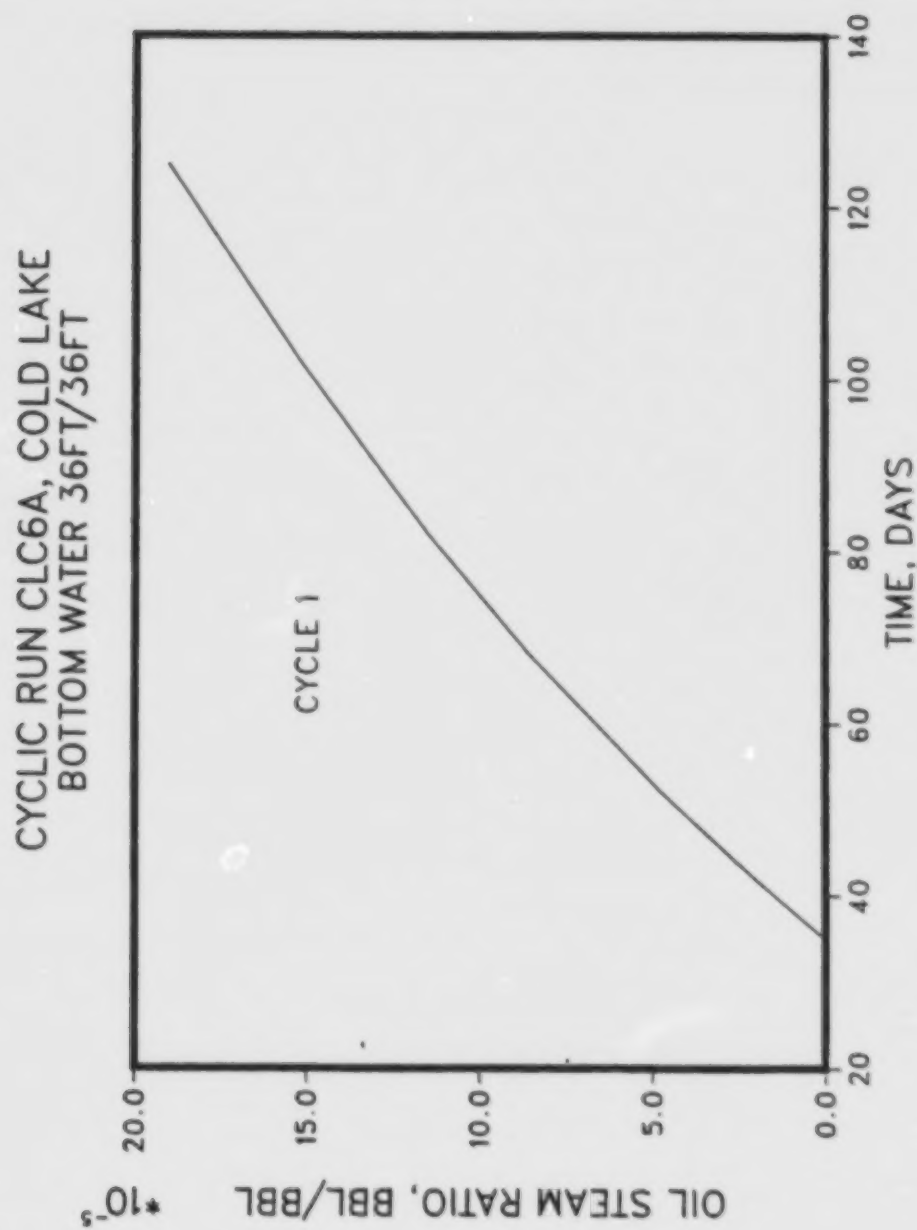


Figure 6.79 Oil-Steam Ratio for Cold Lake Cyclic Run CLC6A, Bottom Water

CYCLIC RUN CLC11A, COLD LAKE BOTTOM WATER 36FT/36FT

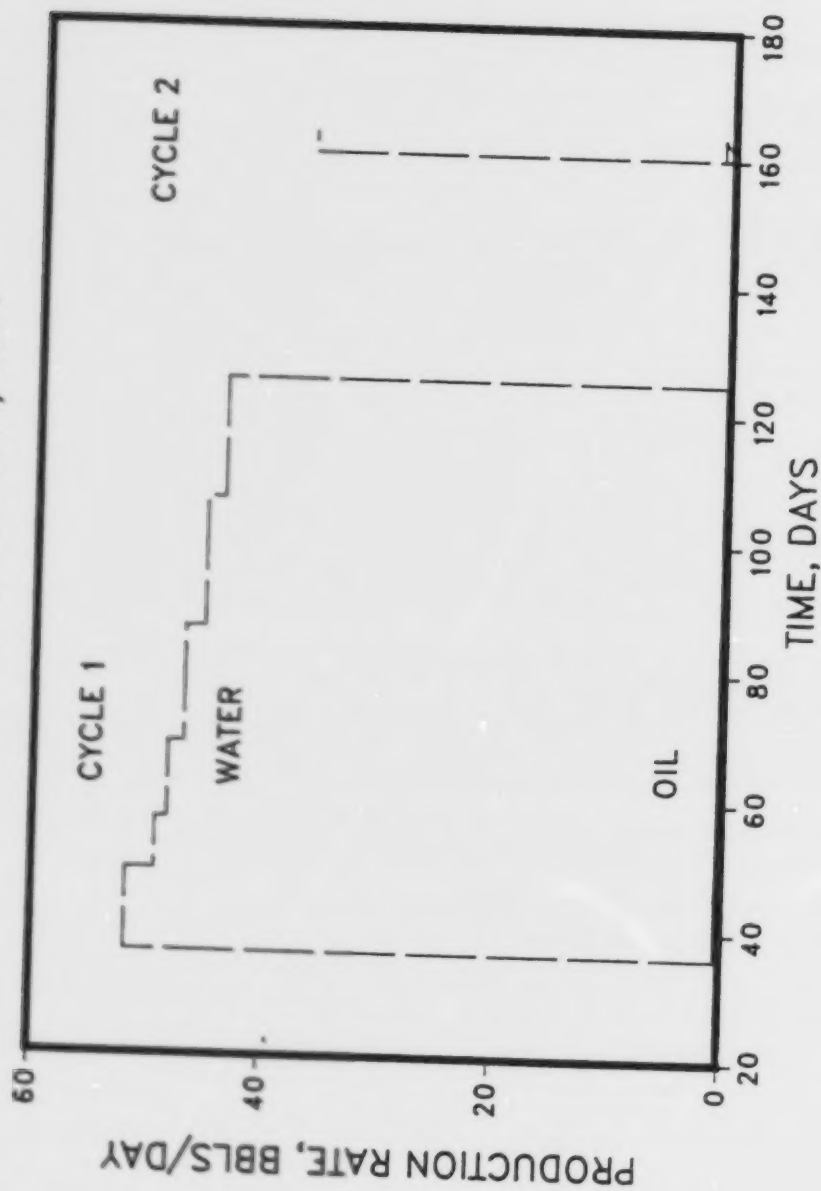


Figure 6.80 Production History for Cold Lake Cyclic Run CLC11A, Bottom Water

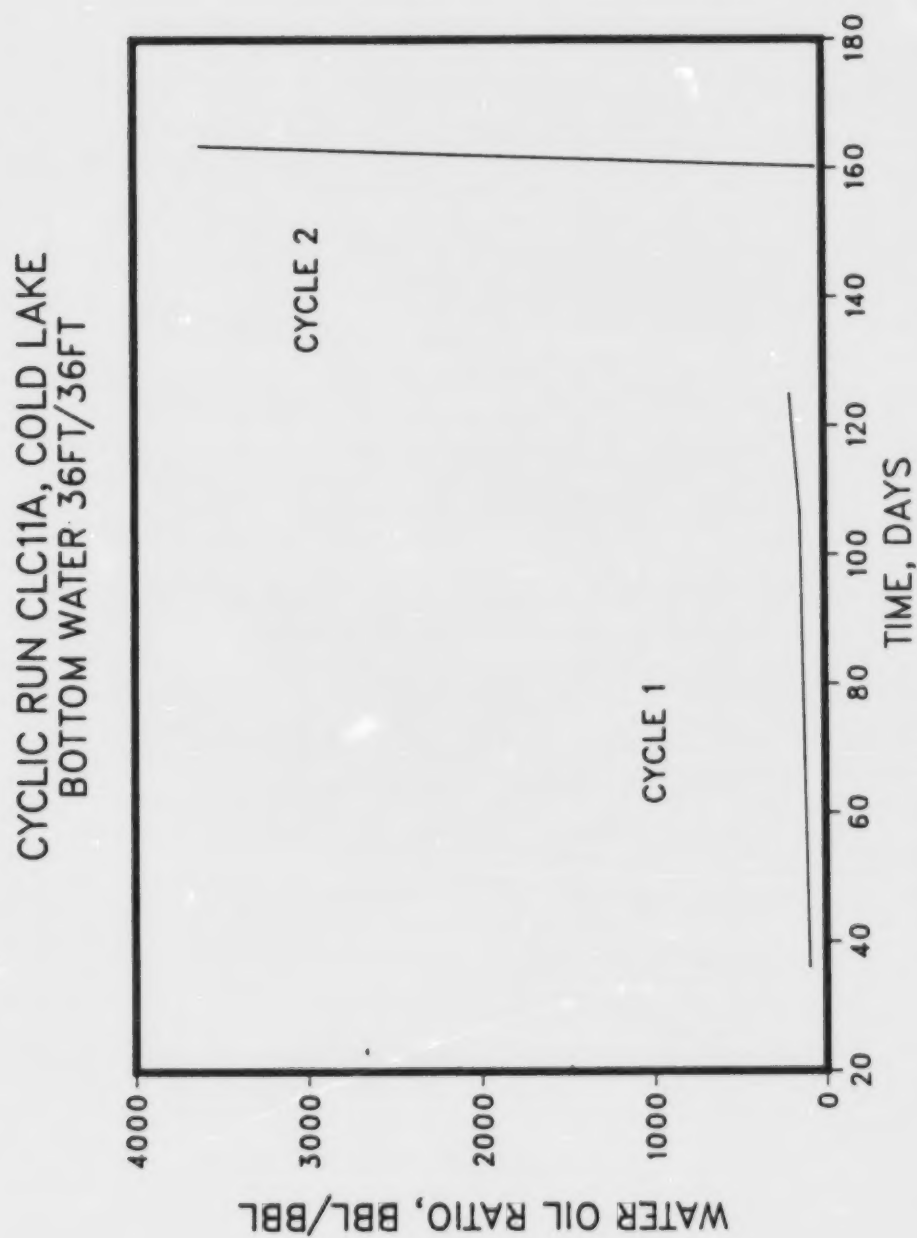


Figure 6.81 Water-Oil Ratio for Cold Lake Cyclic Run CLC11A, Bottom Water

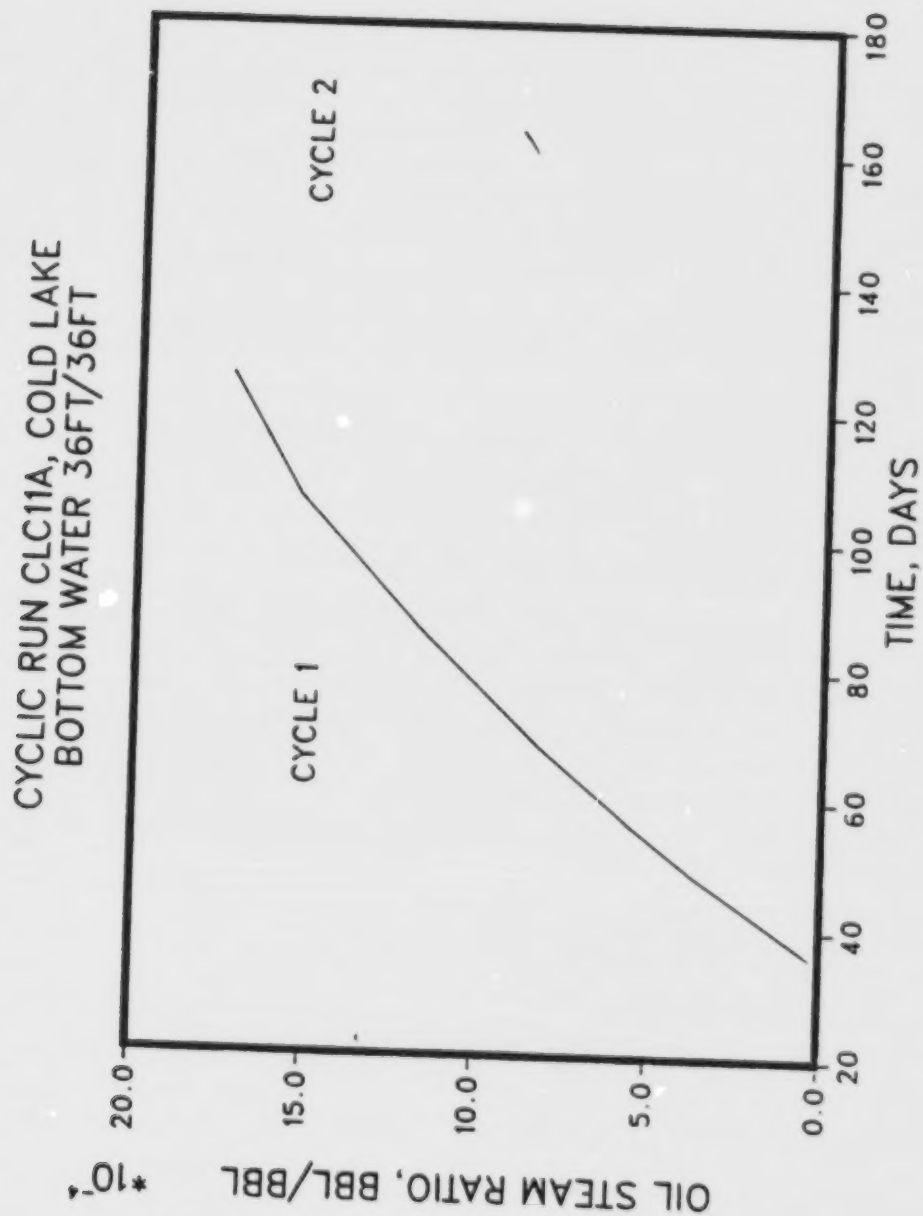


Figure 6.82 Oil-Steam Ratio for Cold Lake Cyclic Run CLC11A, Bottom Water

In the absence of bottom water, the performance in the three-cycle run (CLC1A) is rather poor, in view of the high oil viscosity in Cold Lake (125,000 cp). The overall oil-steam ratio is 0.0147. The heating of the formation was found to be quite uniform, with a higher steam saturation in the upper part of the formation. The terminal oil production rate was only 0.5 B/D, compared to 162 B/D for water. It should be noted that the cyclic steaming process that has been relatively successful in Cold Lake is a steam fracturing based process, whereas in the present simulations, uniform steam advance is assumed. Steam fracturing helps to spread most of steam away from the wellbore, while in the present simulations, water saturation builds up around the wellbore.

Runs CLC6A and CLC11A were similar in performance, in that the oil-steam ratios were extremely low (0.0001 and 0.001, respectively, for the first cycle), although the bottom water thickness in the first run was much less. What these results show is that in the case of a very high viscosity oil, even a small amount of bottom water adversely affects performance.

The above results show, first, that the cyclic steaming performance simulation for Cold Lake, where steam parting is commonly used, cannot be realistically simulated by a non-frac simulator, such as the present one, and secondly, even small amounts of bottom water are likely to lower steam stimulation performance greatly for a very high viscosity oil.

Simulation of a Laboratory Steamflood

An important application of the simulators of the type developed in this work is their ability to interpret the results of laboratory experiments. In the present work, an attempt was made to evaluate a scaled model experiment of steamflooding, the data for which was reported by Proctor (1986). A scaled model is based upon scaling criteria derived from the partial differential equations of the process, in this case, steamflooding. First, the nonlinear equations must be simplified considerably before scaling criteria can be derived,

in order to minimize temperature and concentration dependence of various properties, and second, practical considerations make it difficult to satisfy all of the criteria derived. As a result, some of the scaling criteria must be relaxed. The question remains: what is the error due to neglecting these criteria? The steamflooding scaling criteria have been discussed by various investigators (e.g. Kimber and Farouq Ali (1986)). It has been shown that in none of the cases considered can the scaling criteria be fully satisfied. Two different experimental approaches have been employed for steamflooding experiments: low pressure models, where the operation is at pressures close to the atmospheric pressure, and high pressure models, where the operation is close to the field conditions. Neither approach permits the use of the field porous media and fluids. (Kimber and Farouq Ali showed that this would be feasible only if the model is geometrically distorted, and other groups relaxed). This is so because the model permeability must be scaled up by the geometric scaling factor. As a result, the model and field relative permeabilities are expected to be different (the end point saturations are different, for example), although these are assumed to be the same.

Over 25 steamflood simulations were carried out to try to simulate Proctor's Run 10, the conditions for which are listed in Table 6.4, and the production history for which is given in Table 6.5. Figure 6.83 shows the experimental and simulated production histories for this run. The history match runs were designed to match the experimental data without major adjustments in data. Block size, initial conditions, and transmissibilities were varied in these runs, with little success. Finally, only major adjustments in the critical saturations and transmissibilities permitted the match shown in Fig. 6.83. This match could have been further improved, but what is important is the finding that large adjustments of field relative permeabilities are necessary to achieve a match. Scaled model experiments using reservoir porous media and fluids are currently in progress, and it is too early to say whether they offer a solution to this problem.

Table 6.4

DATA USED FOR THE SIMULATION OF LABORATORY RUN 10

Dimensions of Porous Pack, ft	2.665 x 2.665
Thickness, ft	0.208
Initial Oil Saturation, %	70.0
Initial Pressure, psia	10.0
Permeability, darcy	4200
Porosity, %	30.23
Oil Compressibility, psi ⁻¹	0.5×10^{-5}
Water Compressibility, psi ⁻¹	0.3×10^{-5}
Oil Thermal Expansion Coefficient, °F ⁻¹	0.5×10^{-3}
Water Thermal Expansion Coefficient, °F ⁻¹	0.49×10^{-3}
Rock Compressibility, psi ⁻¹	1×10^{-6}
Rock Thermal Conductivity, Btu/day-ft-°F	42.3
Thermal Conductivity of Overburden, Btu/day-ft-°F	35.3
Rock Matrix Density, lb/ft ³	165
Rock Matrix Specific Heat, Btu/lb-°F	0.20
Thermal Diffusivity of Overburden, ft ² /day	0.96
Specific Heat of Oil, Btu/lb-°F	0.50
Oil Density, lb/ft ³	58.5
Critical Gas Saturation, %	10.0
Residual Oil Saturation, %	20.0
Irreducible Water Saturation, %	7.5

Oil Viscosity (Oil: Faxam-100)

<u>Temperature, °F</u>	<u>Viscosity, cp</u>
33.8	9256
42.1	4066
59.2	653
75.2	208
95.0	91
180.7	9.4
325	2.8

Avg. Steam Injection Rate, B/D	2.084
Avg. Steam Injection Pressure, psia	15.0
Avg. Steam Quality, %	90.0

Table 6.5

EXPERIMENTAL DATA FOR RUN 10; STEAMFLOOD IN ABERFELDY MODEL

Type of Oil Used	Faxam-100 (208 mPa·s at 23°C)
Pore Volume	12700 cm ³
Porosity of Bead Pack	30.23%
Hydrocarbon Pore Volume	11680 cm ³
Initial Oil Saturation	92.00%
Irreducible Water Saturation	8.00%
Initial Model Temperature	4.07°C
Water Feed Flow Rate	199.8 cm ³ /min
Boiler Feed Flow Rate	30.3 cm ³ /min
Total Flow Rate of Steam	230.1 cm ³ /min
Volume of Steam Injected	26850 cm ³ (2.114 PV)
Volume of Oil Recovered	3677 cm ³ (31.48% OOIP)

Cumulative Total PV Injected (cm ³)	Cumulative Total PV Injected (PV)	Cumulative Oil Produced (cm ³)	Cumulative Oil Produced (%OOIP)	Oil-Steam Ratio (cm ³ /cm ³)
1100	0.087	540	4.62	0.4909
2830	0.223	895	7.66	0.2052
4280	0.337	1245	10.66	0.2414
6085	0.479	1690	14.47	0.2465
7575	0.596	1897	16.24	0.1389
9265	0.730	2027	17.35	0.0769
10760	0.847	2234	19.13	0.1385
12550	0.988	2399	20.54	0.0922
14240	1.212	2624	22.47	0.1331
16050	1.264	2749	23.54	0.0691
17745	1.397	2859	24.48	0.0649
19535	1.538	2998	25.67	0.0776
21335	1.680	3162	27.07	0.0911
23135	1.822	3304	28.29	0.0789
24030	1.892	3381	28.95	0.0860
24950	1.965	3422	29.30	0.0446
26850	2.114	3677	31.48	0.1342

SIMULATION OF SCALED MODEL RUN 10

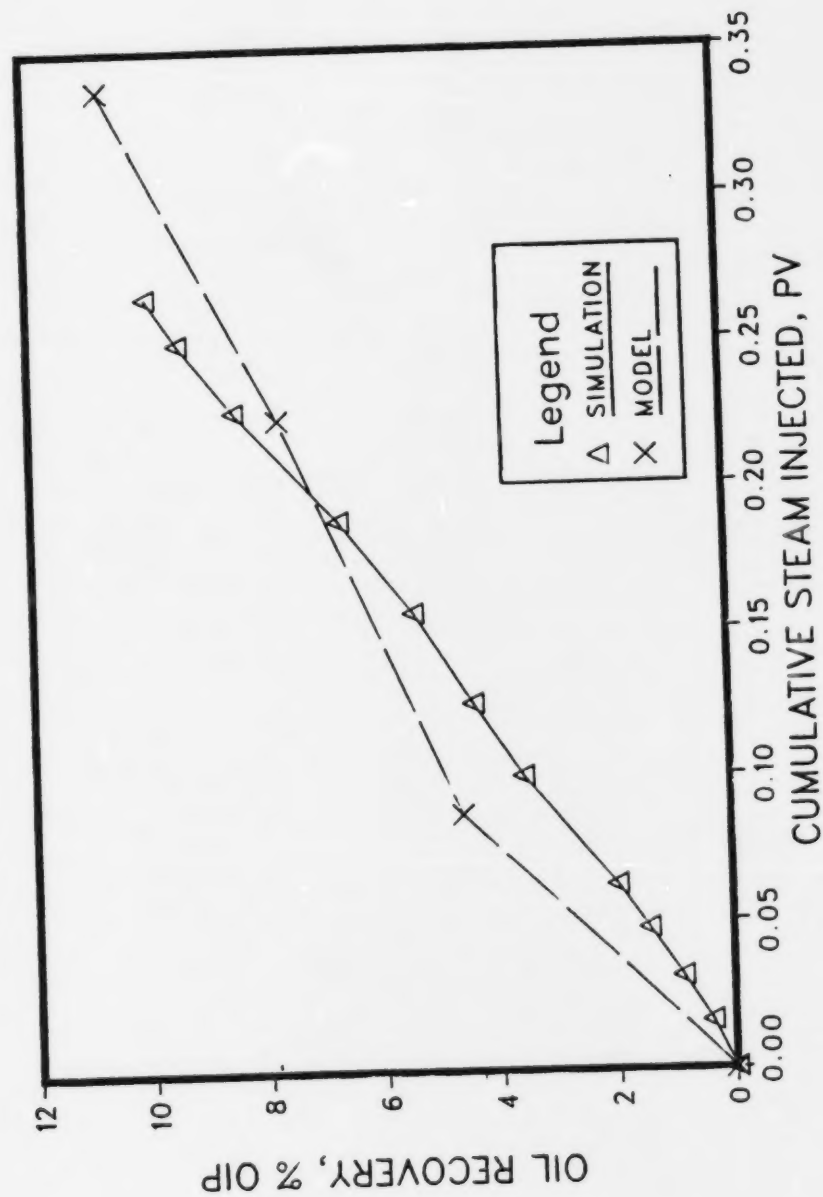


Figure 6.83 Simulation of Scaled Model Steamflood Run 10, Oil Recovery vs. Steam Injected (Proctor).

Non-Newtonian Oil Viscosity Effects

In Chapter IV, a possible model was discussed for non-Newtonian oils. It has been claimed from time to time that certain Alberta, Saskatchewan and Venezeula oils behave in the non-Newtonian manner. In the present work, it is intended to show the effect of such oil rheology on steamflooding response. Table 6.6 gives the production performance summary for a base steamflood (SP1), with no bottom water, or any non-Newtonian or other effects. The oil/water production and oil-steam ratio plots are given in Figs. 6.84 and 6.85. The oil recovery at the end of 843 days is seen to be 12.47%, with a cumulative oil-steam ratio of 0.413.

Table 6.7 gives the production history of the same run, but with the assumption that the oil is non-Newtonian, with an exponent of 0.9, at all temperatures (Run SP5). The effect of such a value of the exponent will be to reduce the oil viscosity by one-half approximately, at typical shear rates involved. Figures 6.86 and 6.87 give the production histories and the oil-steam ratio for this run. It is seen that the oil recovery at the same steam injection time is 8.24% versus 4.15% for Newtonian behaviour (626 days). The corresponding oil-steam ratios are 0.367 and 0.185, respectively. The increase in oil recovery and the oil-steam ratio is due to decreased oil viscosity in the non-Newtonian case. It is important to note that within our assumptions, such a decrease is occurring regardless of temperature. In other words, the cold oil mobility is increased, and the oil behaves like a less viscous oil, although in a nonlinear manner. The observed improvements in performance would be obtained also if the steamflood is carried out in a less viscous oil.

In a typical steamflood, oil-water emulsions may form in certain temperature regions, although these were not considered in this work. Such emulsions would behave in a non-Newtonian manner. Depending on the rheology of such emulsions, they may not reduce oil mobility, if they are shear-thinning. Field experience in steamflooding shows that

Table: 6.6
BASE RUN: ABERFELDY (NO BOTTOM WATER) SP1
NO FOAM, NO LIPGRADING, NO NON-NEWTONIAN
INJ. RATE 600 BBLS/DAY STEAMFLOOD

Legend:

T : Time, Days
 OPR : Oil Production Rate, Bbls/Day
 WPR : Water Production Rate, Bbls/Day
 WOR : Cumulative Water-Oil Ratio, Bbl/Bbl
 CSI : Cumulative Steam Injected, 10^5 Bbls
 ORec : Oil Recovery, %
 OSR : Cumulative Oil-Steam Ratio, Bbl/Bbl

T	OPR	WPR	WOR	CSI	ORec	OSR
44	19.3	249	12.80	0.26	0.05	0.032
90	20.1	307	15.20	0.54	0.11	0.033
130	21.4	363	16.90	0.78	0.16	0.033
174	30.4	505	16.60	1.04	0.23	0.036
215	40.1	585	14.60	1.29	0.32	0.041
253	50.6	630	12.40	1.52	0.43	0.047
294	56.9	657	11.50	1.76	0.56	0.053
331	63.9	671	10.50	1.98	0.69	0.058
370	73.9	682	9.23	2.22	0.85	0.064
413	90.4	692	7.66	2.48	1.07	0.072
460	124.0	690	5.56	2.76	1.37	0.083
501	184.0	698	3.79	3.00	1.75	0.098
546	292.0	749	2.56	3.27	2.44	0.125
586	353.0	989	2.80	3.52	3.19	0.152
626	441.0	1246	2.82	3.76	4.15	0.185
667	474.0	960	2.02	4.00	5.28	0.221
703	542.0	775	1.43	4.22	6.38	0.253
742	633.0	720	1.14	4.45	7.75	0.292
788	737.0	664	0.90	4.73	9.66	0.342
820	860.0	696	0.81	4.92	11.20	0.381
843	1047.0	765	0.73	5.06	12.47	0.413

BASE RUN: ABERFELDY, NO BOTTOM WATER SP1
 NO FOAM, NO UPGRADING, NO NON-NEWTONIAN
 INJ. RATE 600 BBLS/DAY STEAMFLOOD

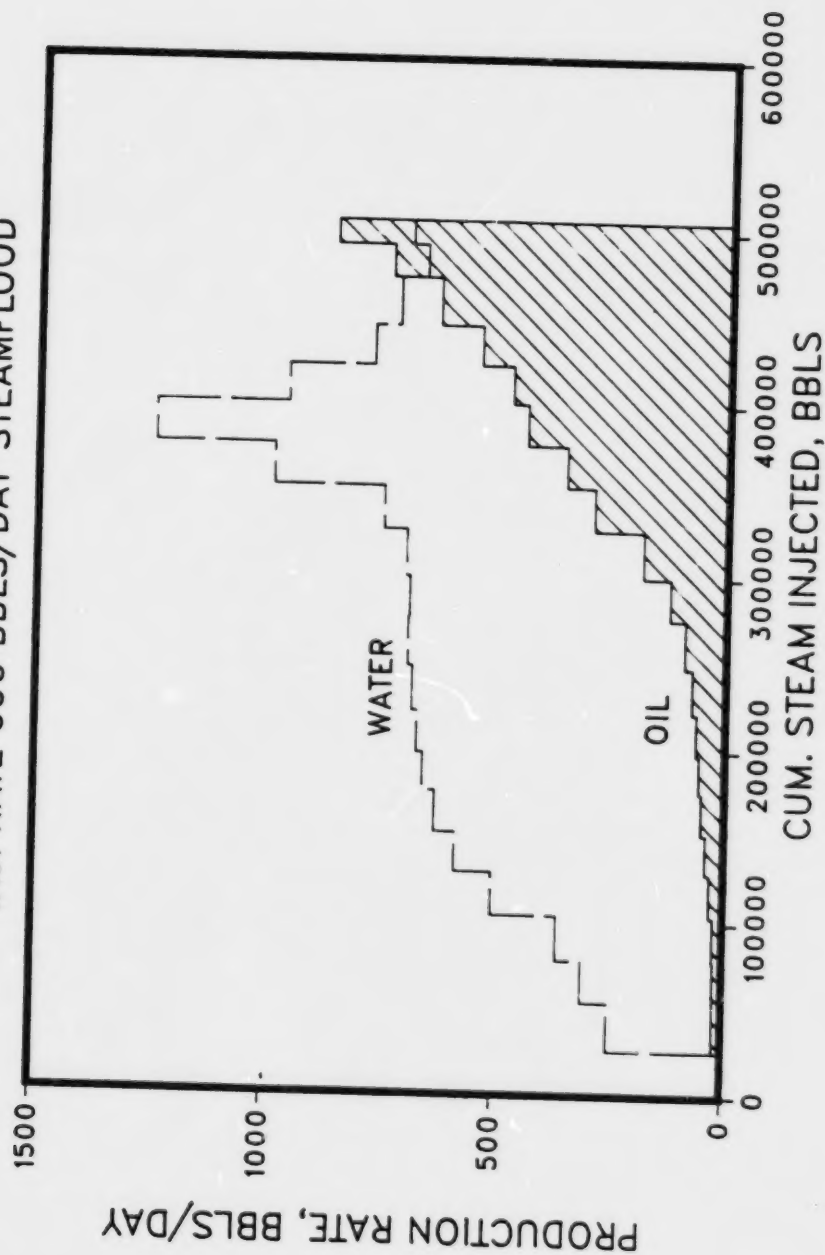


Figure 6.84 Production History of Base Aberfeldy Steamflood Run SP1, for Special Features Studies

BASE RUN: ABERFELDY, NO BOTTOM WATER SP1
NO FOAM, NOLIPGRADING, NO NON-NEWTONIAN
INJ. RATE 600 BBL/DAY STEAMFLOOD

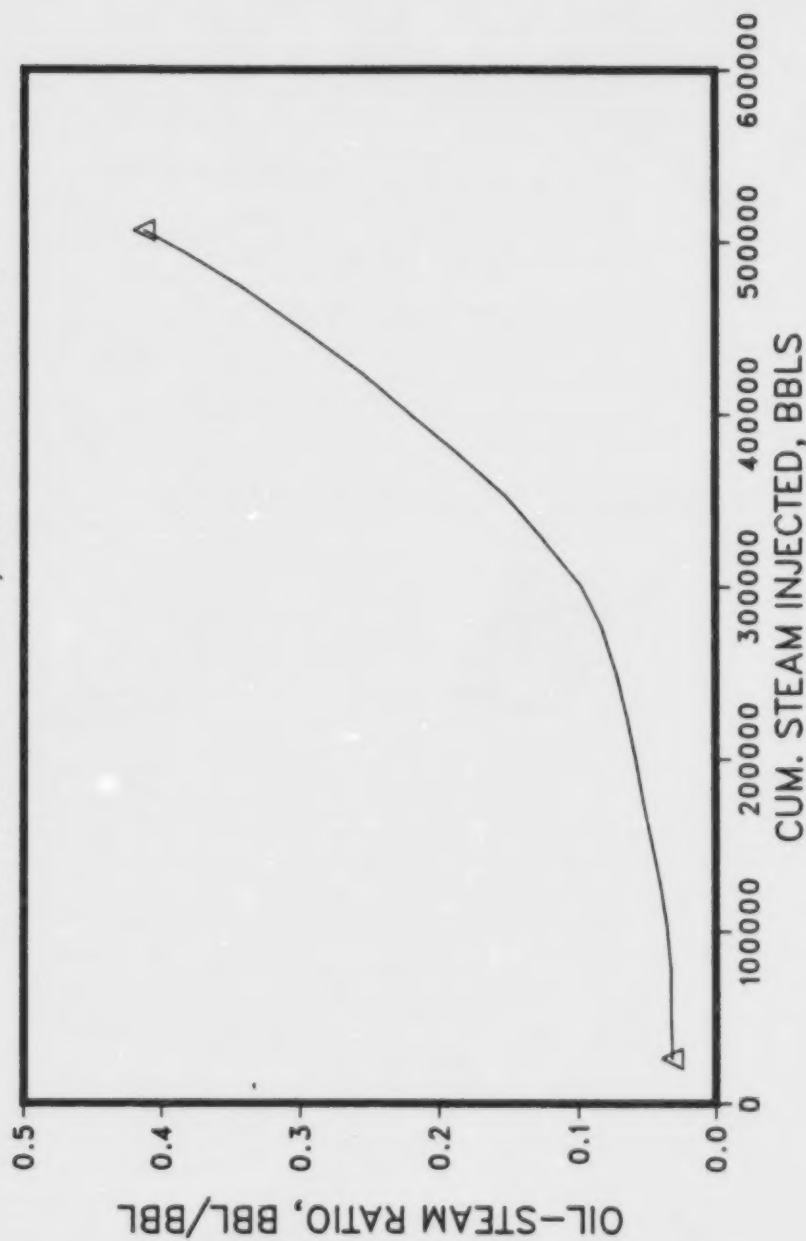


Figure 6.85 Oil Recovery of Base Aberfeldy Steamflood Run SP1, for Special Features Studies

Table: 6.7
 NON-NEWTONIAN RUN: ABERFELDY (NO BOTTOM WATER) SP5
 INJ. RATE 600 BBL/DAY STEAMFLOOD

Legend:

T : Time, Days
 OPR : Oil Production Rate, Bbls/Day
 WPR : Water Production Rate, Bbls/Day
 WOR : Cumulative Water-Oil Ratio, Bbl/Bbl
 CSI : Cumulative Steam Injected, 10^6 Bbls
 ORec : Oil Recovery, %
 OSR : Cumulative Oil-Steam Ratio, Bbl/Bbl

T	OPR	WPR	WOR	CSI	ORec	OSR
42	47.0	242	5.13	0.254	0.12	0.0796
99	51.3	310	6.03	0.593	0.29	0.0813
128	54.2	348	6.41	0.770	0.38	0.0830
171	74.5	467	6.27	1.027	0.55	0.0894
213	97.6	541	5.54	1.279	0.77	0.1010
251	123.0	580	4.72	1.509	1.03	0.1140
294	137.0	605	4.41	1.766	1.36	0.1290
330	150.0	615	4.08	1.981	1.67	0.1410
369	169.0	622	3.68	2.216	2.05	0.1550
414	198.0	628	3.18	2.481	2.54	0.1720
459	246.0	630	2.56	2.753	3.16	0.1920
504	339.0	646	1.90	3.027	3.96	0.2190
546	566.0	850	1.50	3.273	5.04	0.2580
586	702.0	1245	1.77	3.516	6.61	0.3150
628	634.0	1042	1.64	3.770	8.32	0.3690

NON-NEWTONIAN RUN: ABERFELDY, NO BOTTOM WATER SP5
 INJ. RATE 600 BBLs/DAY STEAMFLOOD

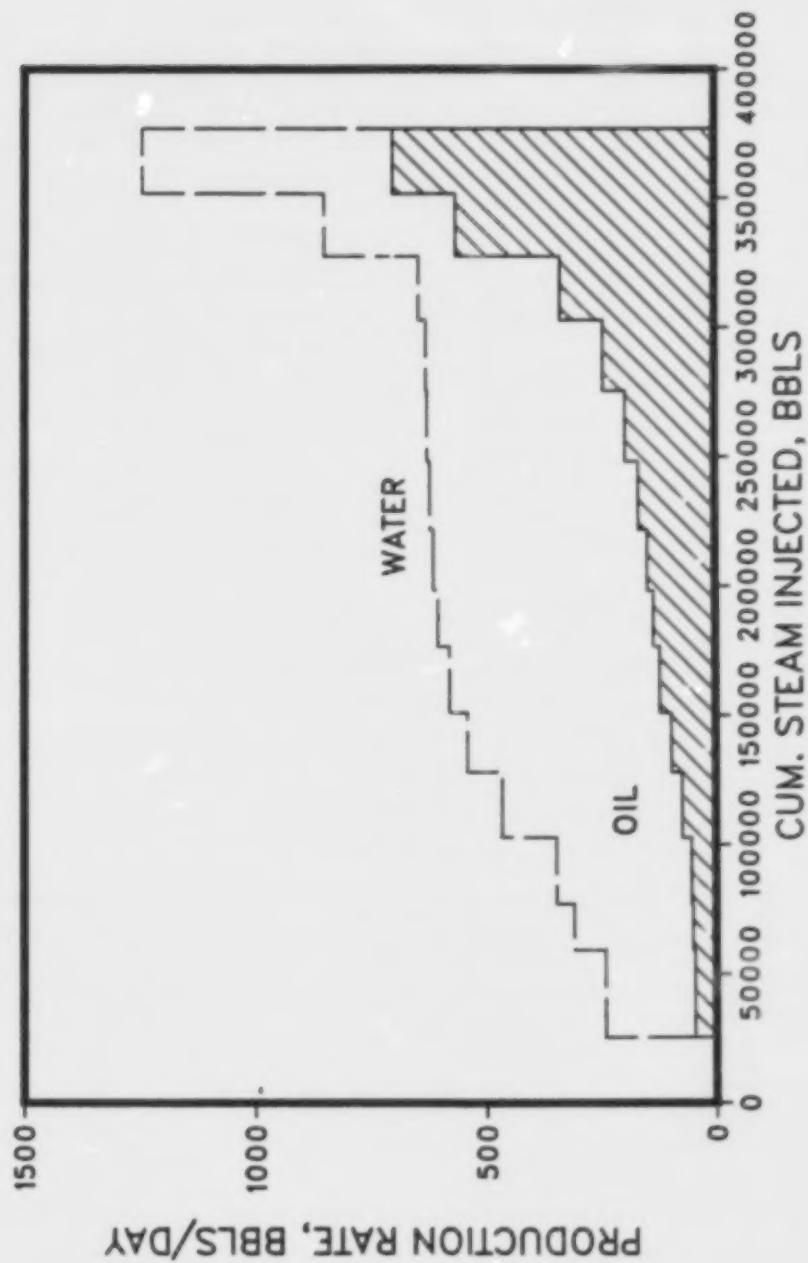


Figure 6.86 Production History of Aberfeldy Run SP5, for Non-Newtonian Oil ($n = 0.9$)

NON-NEWTONIAN RUN: ABERFELDY, NO BOTTOM WATER SP5
INJ. RATE 600 BBL/DAY STEAMFLOOD

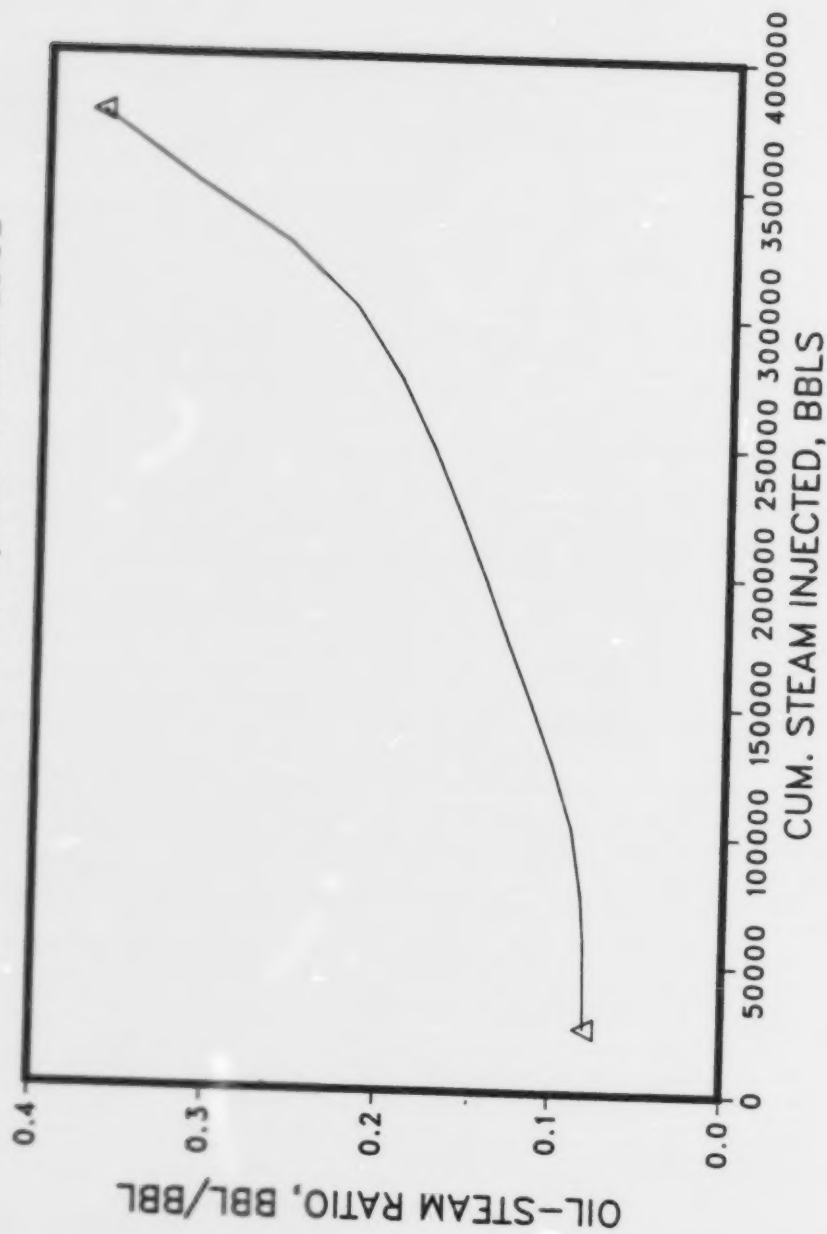


Figure 6.87 Oil-Steam Ratio of Aberfeldy Run SP5, for Non-Newtonian Oil ($n = 0.9$)

emulsions are not a serious problem. This is not so in fireflooding, where emulsions formed are highly viscous, and as a result, the rheology considered in the present simulation does not help much.

Thermal Upgrading

Thermal upgrading was discussed in Chapter IV, where a mathematical representation was given of the thermal upgrading process. Using the viscosity model developed, Run SP3 was carried out. The results were virtually the same as that for the base run (Table 6.6), with 0.1% higher oil recovery. An examination of the temperature profiles showed that the reason for no upgrading effect on oil recovery was the fact that the upgrading process lowered oil viscosity only in the parts of the reservoir with high temperatures, where the oil was mobile enough already. Upgrading had no effect on oil viscosity in the cold parts of the formation where it could have done some good. A second run (SP4) was carried out with slightly higher upgrading parameters. The simulation results are summarized in Table 6.8, and plotted in Figs. 6.88 and 6.89 for this run. There is a small improvement in this case, with oil recovery increasing to 13.02%.

It can be said that thermal upgrading is not likely to be significant in steamfloods of short duration, and prior to steam breakthrough. If a steamflood is continued after steam breakthrough, the oil around the producers would undergo some thermal upgrading leading to a reduction in viscosity. Also, in long-term projects, utilizing conductive heating of oil, thermal upgrading would be an important factor (e.g. Peace River project). It is thus desirable to include thermal upgrading effects in a steam injection simulator.

Foam Injection

Injection of a thermally stable foam prior to steam, or with steam, is being tested in the field. Foams are known to reduce the relative permeability to gas, without affecting oil relative permeability to any appreciable degree. In steam injection, foams are primarily

Table: 6.8
UPGRADING RUN: ABERFELDY (NO BOTTOM WATER) SP4
INJ. RATE 600 BBL/DAY STEAMFLOOD

Legend:

T : Time, Days
OPR : Oil Production Rate, Bbls/Day
WPR : Water Production Rate, Bbls/Day
WOR : Cumulative Water-Oil Ratio, Bbl/Bbl
CSI : Cumulative Steam Injected, 10⁵Bbls
ORec : Oil Recovery, %
OSR : Cumulative Oil-Steam Ratio, Bbl/Bbl

T	OPR	WPR	WOR	CSI	ORec	OSR
44	21.6	248	11.50	0.262	0.06	0.0360
110	23.0	334	14.60	0.661	0.14	0.0367
130	23.8	361	15.20	0.781	0.17	0.0372
172	33.2	498	15.00	1.031	0.25	0.0403
211	42.9	574	13.40	1.264	0.34	0.0450
258	56.9	628	11.00	1.547	0.49	0.0528
295	63.4	652	10.30	1.771	0.62	0.0589
330	70.7	664	9.40	1.978	0.76	0.0645
366	81.1	675	8.33	2.199	0.93	0.0709
418	103.0	686	6.64	2.507	1.21	0.0812
458	135.0	684	5.05	2.751	1.51	0.0920
502	206.0	696	3.37	3.014	1.96	0.1090
546	320.0	740	2.31	3.278	2.70	0.1380
585	389.0	991	2.55	3.511	3.50	0.1670
626	481.0	1244	2.58	3.755	4.58	0.2040
667	506.0	952	1.88	4.001	5.78	0.2420
704	574.0	777	1.35	4.222	6.98	0.2770
741	645.0	707	1.10	4.448	8.36	0.3150
792	757.0	656	0.87	4.751	10.48	0.3700
824	885.0	694	0.78	4.947	12.08	0.4090
841	1024.0	748	0.73	5.045	13.02	0.4320

UPGRADING RUN: ABERFELDY, NO BOTTOM WATER SP4
INJ. RATE 600 BBLs/DAY STEAMFLOOD

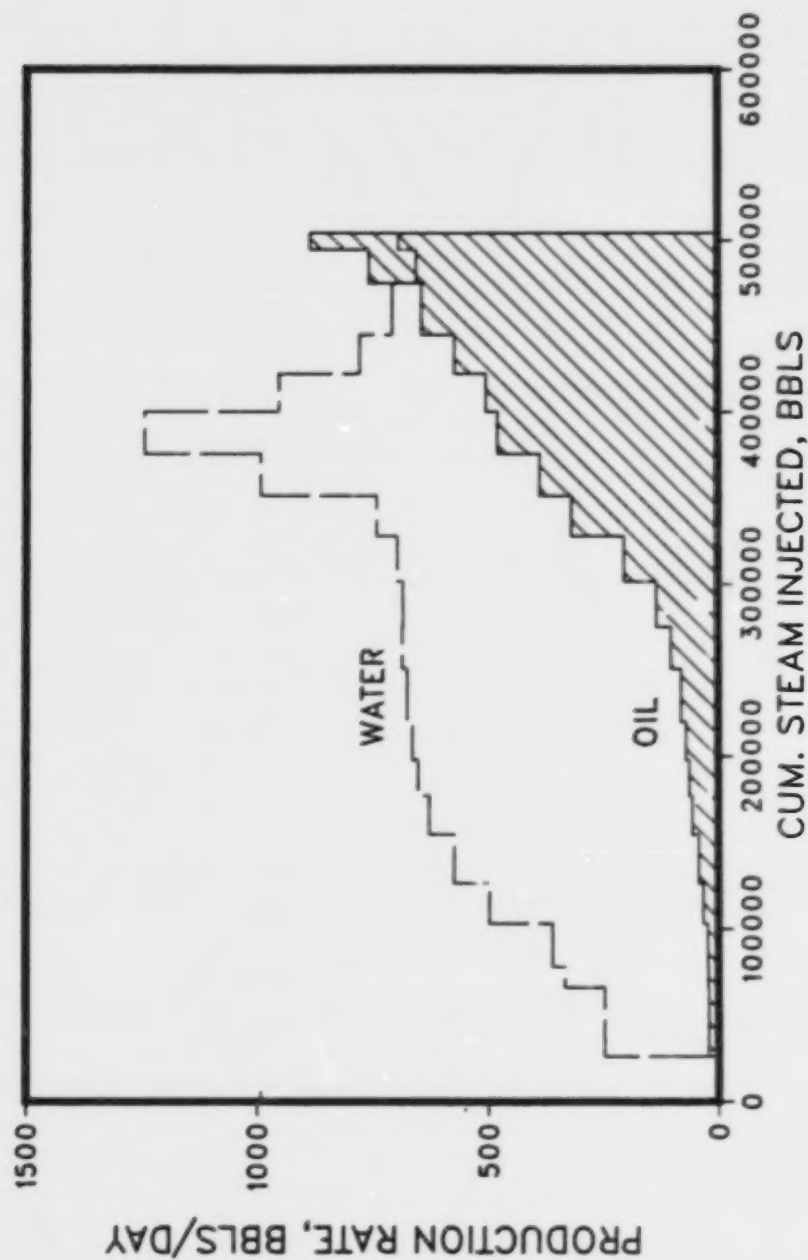


Figure 6.88 Production History of Aberfeldy Run SP4, for Oil Thermal Upgrading

UPGRADING RUN: ABERFELDY, NO BOTTOM WATER SP4
INJ. RATE 600 BBL/DAY STEAMFLOOD

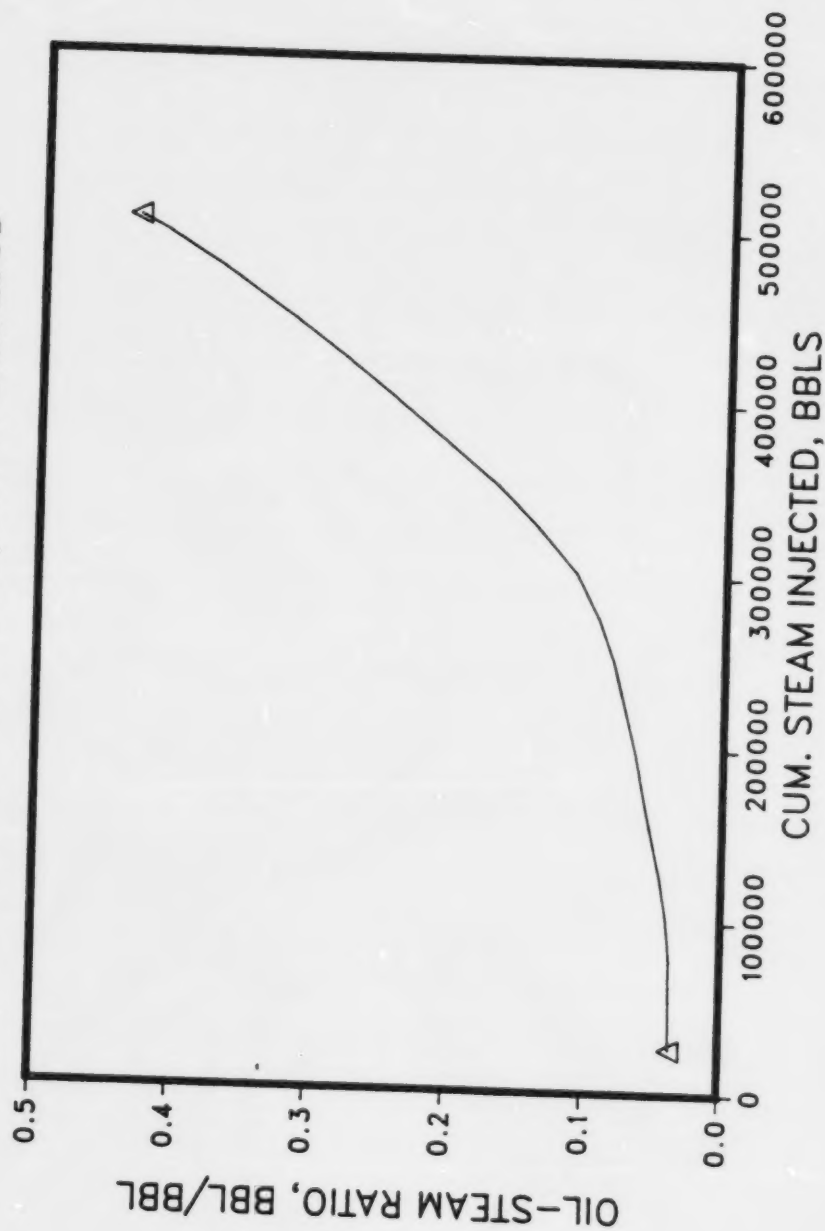


Figure 6.89 Oil-Steam Ratio of Aberfeldy Run SP4, for Oil Thermal Upgrading

being applied as diverting or blocking agents, with limited success. In the present work, a foam is considered to be a gas (steam) permeability reducing agent, plus a viscous material, the viscosity of which is shear-dependent. The foam model was discussed in Chapter IV. Table 6.9 gives the results for a run, comparable to the base run (Table 6.6), in which foam was assumed to be injected. The production history and the oil-steam ratio plots are given in Figs. 6.90 and 6.91. It is seen that foam injection leads to an increase in oil recovery as well as oil-steam ratio, these being 13.69% and 0.453, respectively, as compared to 12.47% and 0.413 for the base run. The increase is not large, considering the additional expense of foam injection. Temperature and saturation profiles show that the foam did divert the steam into the lower part of the formation, where a considerable steam saturation developed. The representation of foam in this model is not rigorous. Very little useable and consistent data are available for high temperature foams. Quite apart from that, the inclusion of a foam breakdown temperature in the simulator limits the range of effectiveness of a foam injected with steam.

Effect of Gas Injection on Cyclic Steaming Response

The use of an additive gas with steam has been suggested for cyclic steaming operations. The injected gas may consist of natural gas, carbon dioxide, or a mixture of carbon dioxide and nitrogen. One long run was carried out to simulate gas injection following steam injection, for six cycles. In this simulation, Cold Lake data were used with a formation thickness of 158 ft. The K-values were a function of pressure and temperature. Steam was injected at a rate of 550 B/D for 45 days, following which natural gas was injected at a rate of 500 Mscf/day for 5 days, before putting the well on production. This was repeated for each of the six cycles. The production history for the six cycles is shown in Fig. 6.92. The overall oil-steam ratio was 0.127, which is quite low compared to typical values in Cold Lake, without the use of a gas. It can be said that gas injection with steam does not appear to lead to a significant increase in oil-steam ratio.

Table 6.9
FOAM RUN: ABERFELDY (NO BOTTOM WATER) SP2
INJ. RATE 600 BBL/DAY STEAMFLOOD

Legend:

T : Time, Days
OPR : Oil Production Rate, Bbls/Day
WPR : Water Production Rate, Bbls/Day
WOR : Cumulative Water-Oil Ratio, Bbl/Bbl
CSI : Cumulative Steam Injected, 10^5 Bbls
ORec : Oil Recovery, %
OSR : Cumulative Oil-Steam Ratio, Bbl/Bbl

T	OPR	WPR	WOR	CSI	ORec	OSR
5	19.6	28	14.50	0.03	0.01	0.032
44	19.4	249	12.80	0.26	0.05	0.032
90	20.2	301	14.90	0.54	0.11	0.033
129	21.6	364	16.90	0.78	0.15	0.033
172	30.5	506	16.60	1.03	0.23	0.037
214	40.1	586	14.60	1.28	0.32	0.041
252	50.8	630	12.40	1.51	0.43	0.047
293	57.1	657	11.50	1.76	0.56	0.053
330	64.1	671	10.50	1.98	0.69	0.059
369	74.0	682	9.21	2.21	0.86	0.065
412	90.5	692	7.65	2.47	1.07	0.072
458	123.0	691	5.59	2.75	1.37	0.083
502	189.0	704	3.73	3.01	1.78	0.099
546	293.0	751	2.56	3.27	2.45	0.125
586	353.0	988	2.80	3.39	3.51	0.152
626	450.0	1292	2.87	3.75	4.17	0.186
667	522.0	1044	2.00	4.00	5.37	0.224
702	634.0	779	1.23	4.21	6.58	0.262
742	765.0	690	0.90	4.45	8.27	0.311
792	872.0	717	0.82	4.75	10.71	0.377
821	988.0	792	0.80	4.93	12.36	0.420
842	916.0	634	0.69	5.05	13.69	0.453

FOAM RUN: ABERFELDY, NO BOTTOM WATER SP2
 INJ. RATE 600 BBLS/DAY STEAMFLOOD

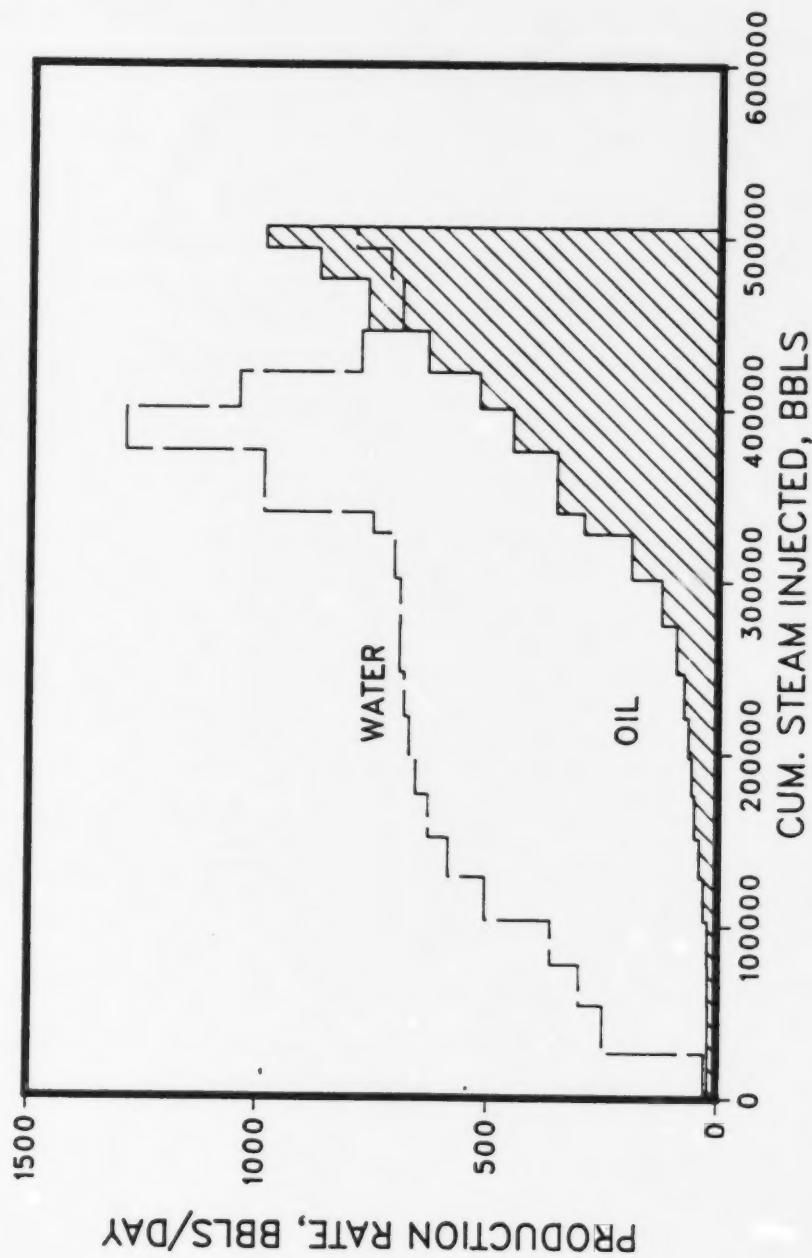


Figure 6.90 Production History of Aberfeldy Run SP2, for Steam Foam Injection

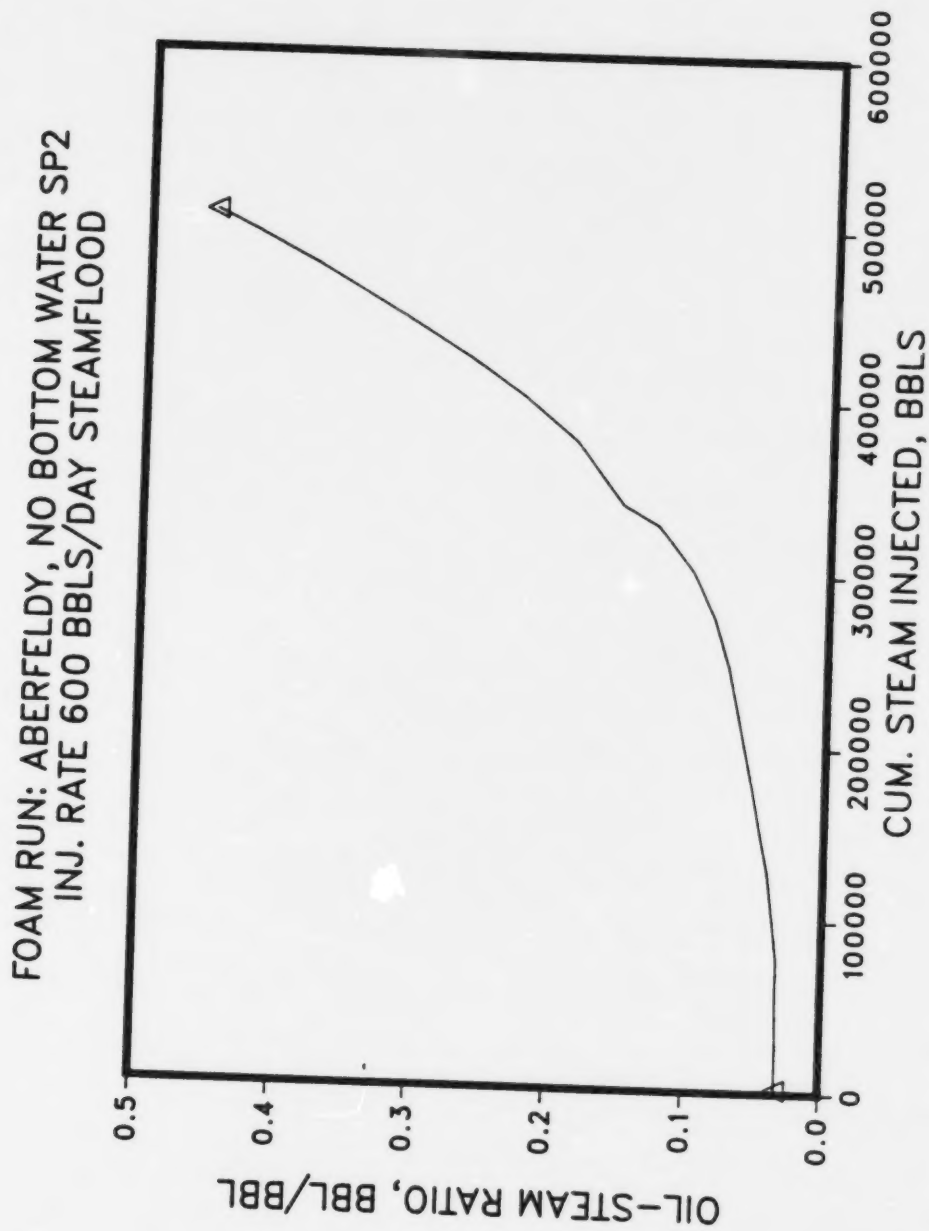


Figure 6.91 Oil-Steam Ratio of Aberfeldy Run SP2, for Steam Foam Injection

CYCLIC STEAM STIMULATION — COLD LAKE
SIX—CYCLE GAS—STEAM INJECTION RUN

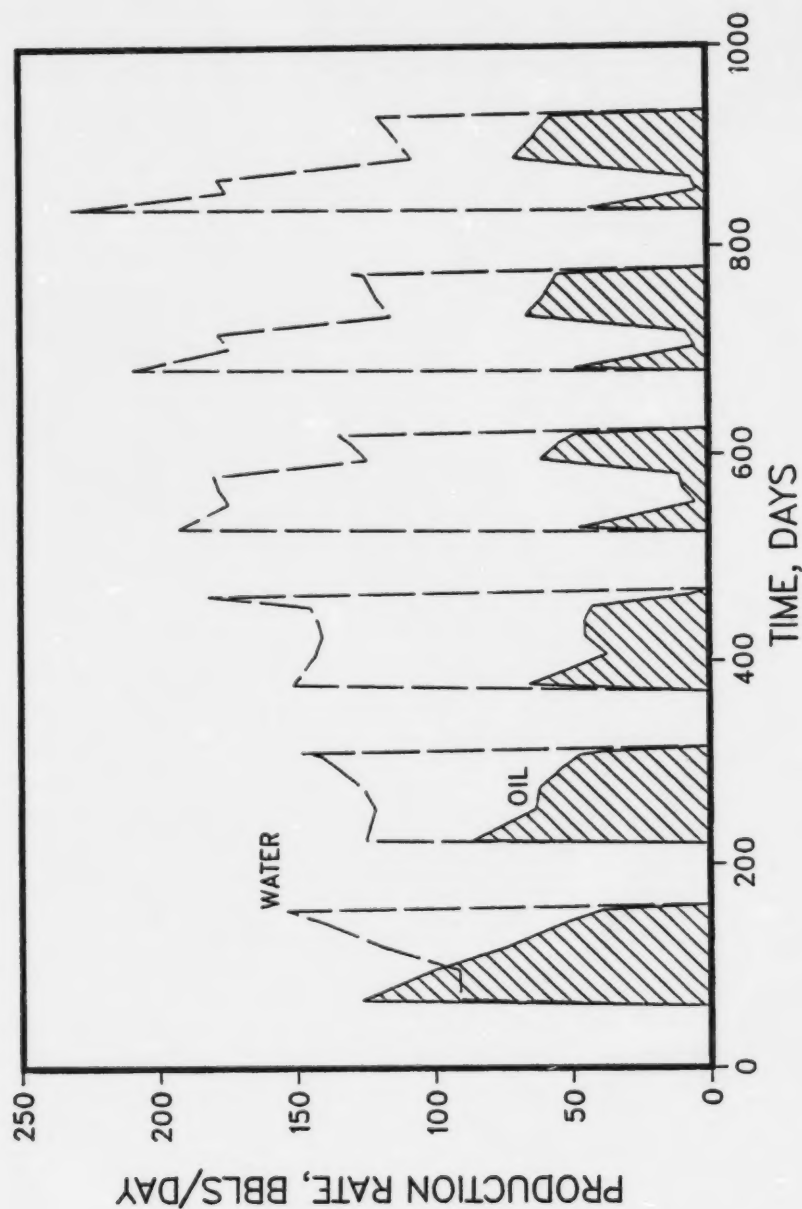


Figure 6.92 Production History of Six-Cycle Gas-Steam Injection Simulation for Cold Lake Reservoir.

Injection of gas following steam imparts additional production energy to the formation, which helps in oil production. It should be noted that the use of an additive gas has been tested over the years in Cold Lake. It has been found to be uneconomical, and is currently used only in special circumstances.

Steam Injection Using Partial Penetration

When bottom water is present, there may be some merit in completing injection and/or production wells partially into the formation. In classical reservoir engineering, partial penetration has been considered for special situations. Flow under partial penetration is a combination of radial and spherical flow. The latter is undesirable, unless special conditions justify that. In steam injection - cyclic and drive - the situation is complicated by heat injection. In this study, several runs were carried out to examine the effect of partial penetration on cyclic steaming and steamflooding response. Results of two runs are discussed below.

Run ABRS1B employs partial penetration in the absence of bottom water, and is comparable to Run ABRS1. Steam is injected over the lower one-half of the formation, while production is from the entire interval. Results for this run are plotted in Figs. 6.44 through 6.46, and are tabulated in Table C.27. It is seen that the oil-steam ratio and the oil recovery in the partial penetration case are lower (0.108 vs. 0.250 and 2.72% vs. 6.25%), at a given time (700 days). This is due to the fact that steam initially heats the lower part of the formation, and the oil viscosity is so high that steam segregation does not become a dominant feature because the oil mobility is too low to promote downward flow. This result is to be expected for a partially penetrating injection well. At long times, however, oil becomes mobile enough to flow downward, and the production rates increase rapidly. For example, the oil recovery at the end of 1100 days is 15.22%.

Figures 6.93 to 6.95, and Table C.28 give the production histories for a three-cycle simulation of the Aberfeldy reservoir, with partial completion (ABC18), when bottom

BOTTOM WATER, 36FT/36FT, CYCLIC RUN: ABERFELDY RUN ABC18
 PARTIAL PENETRATION; COMPLETION TOP 18 FT
 STEAM INJ. 30 DAYS; SOAK 5 DAYS

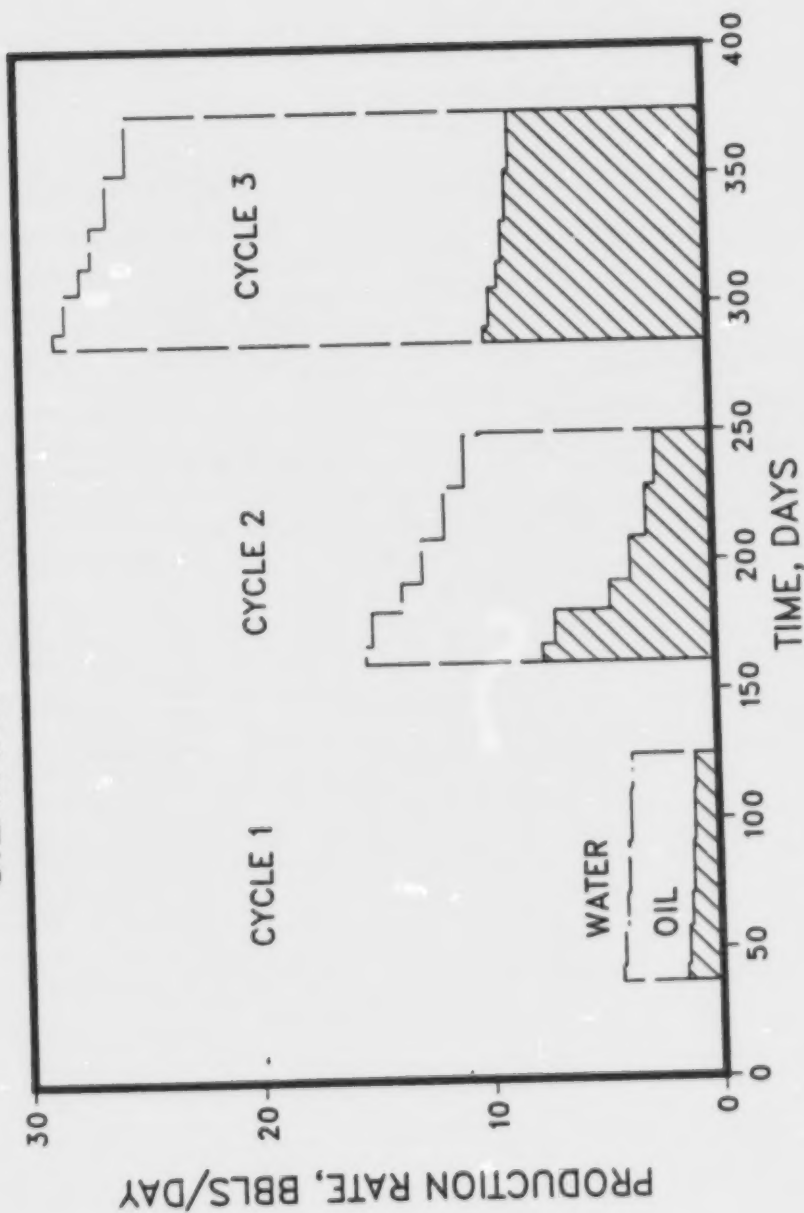


Figure 6.93 Production History of Aberfeldy Cyclic Run ABC18, for Partial Penetration

BOTTOM WATER, 36FT/36FT, CYCLIC RUN: ABERFELDY RUN ABC18
 PARTIAL PENETRATION; COMPLETION TOP 18 FT
 STEAM INJ. 30 DAYS; SOAK 5 DAYS

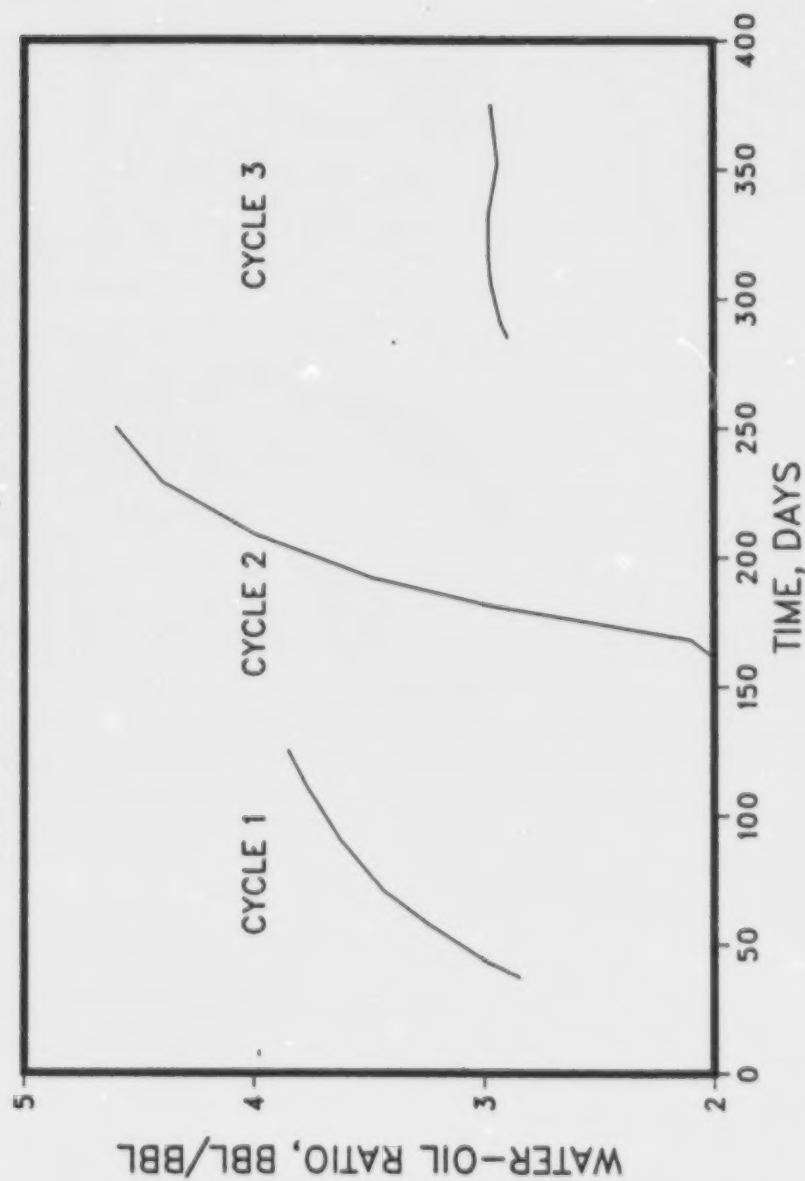


Figure 6.94 Water-Oil Ratio of Aberfeldy Cyclic Run ABC18, for Partial Penetration

BOTTOM WATER, 36FT/36FT, CYCLIC RUN: ABERFELDY RUN ABC18
 PARTIAL PENETRATION; COMPLETION TOP 18 FT
 STEAM INJ. 30 DAYS; SOAK 5 DAYS

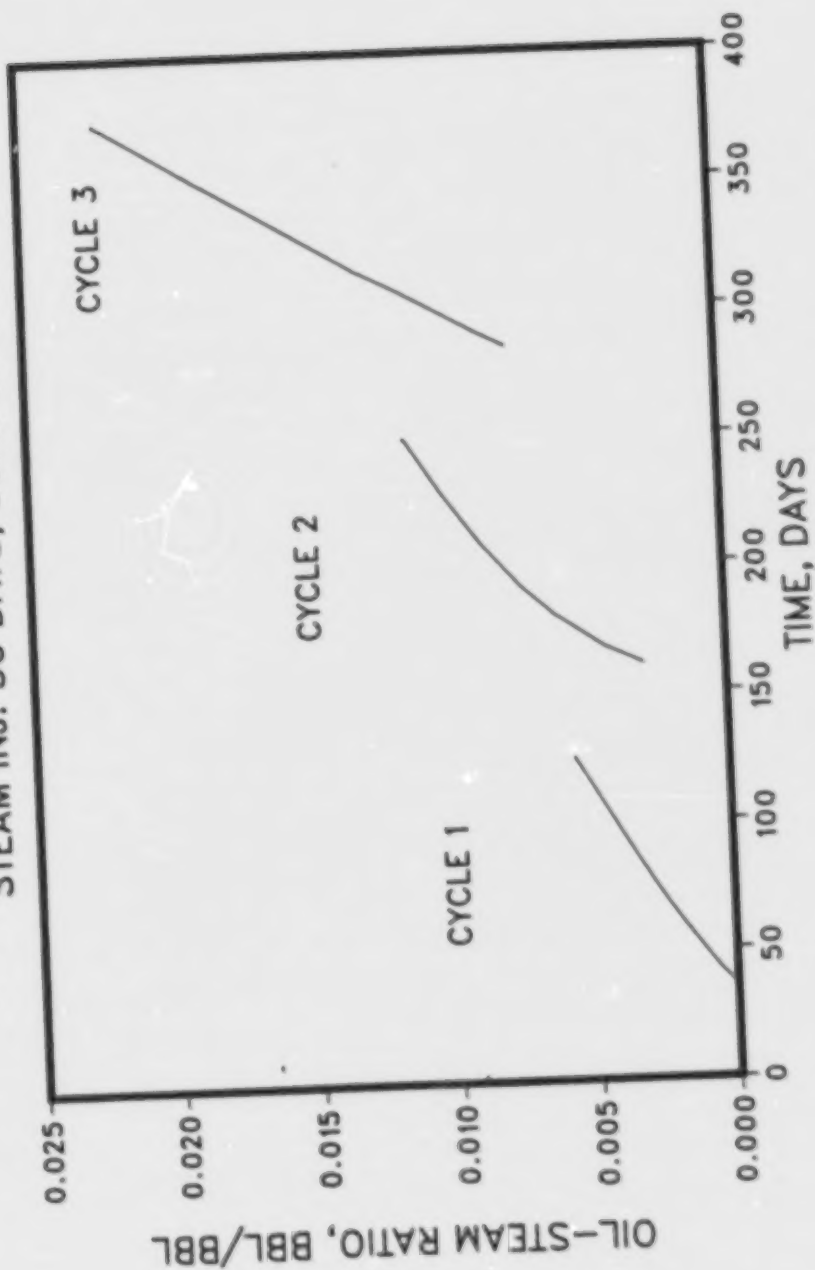


Figure 6.95 Oil-Steam Ratio of Aberfeldy Cyclic Run ABC18, for Partial Penetration

water is present. In this case, steam is injected into the top 18 ft. of the 36 ft. formation, at the base of which there is a water zone, 36 ft. in thickness. The results of this run are comparable to those of Run ABC17. A comparison of all Aberfeldy bottom water cyclic stimulation runs ABC6, 8, 9, 11, and 17 shows that the oil-steam ratio in all cases is higher than that in the case of the partial penetration run. The important difference is that in the full interval completion runs, the water-oil ratios are much higher, e.g. 3 in partial completion vs. 200-300 in full completion. It can be concluded that full interval completion may be practical only if the pumping capacity is large enough, and large volumes of the produced water can be handled.

Partially penetrating cyclic steaming wells do seem to have one advantage: they prevent communication with the bottom water zone, as seen from the low water-oil ratios. The very high water-oil ratios in the case of the full-interval completions in the bottom water situation are due to communication of the perforations with the bottom water zone. On the other hand, the oil production rate in the partial penetration case is very low. Table 6.3(b) shows that the oil production rate improves in succeeding cycles. The water production rates increases also, but the water-oil ratio declines. Possibly, partial penetration oil production would become competitive with the oil production of full-interval completion after many cycles. As such, partial penetration offers an interesting option in cyclic steaming under bottom water situations. Many more simulation studies are needed for fully evaluating partial penetration as an operating strategy in bottom water situations.

Sandface Steam Quality in Thick Formations with Multiple Offtake

General

In steam injection operations - both cyclic steaming and steamflooding - sometimes it is necessary to inject steam into one or more layers of a thick interval, from a single tubing, which is provided with multiple offtakes. In such a case, the bottomhole steam quality and

pressure at each offtake point will vary with time. In some cases, the steam inflow rate into each layer would also vary with time. These changes in steam quality, pressure, and possibly rate with time, at each injection point, are of importance in steam injection processes, especially in steamflooding. Very little field work has been done on this problem. Nothing has been published on the mathematical simulation of wellbore steam flow with multiple offtakes, or steam splitting. In this work, one of the objectives was to develop a mathematical model of steam injection in the wellbore, taking into account the pressure drop due to varying flow regimes, heat loss, and the steam quality. The model considers heat loss to the surrounding media in a rigorous manner.

In the following, first the computed results for steam quality variation with steam injection rate, steam pressure and steam splitting are discussed. Only one case of steam splitting (i.e. taking some of the steam off the tubing at intermediate points) is considered, where one-half of the injected steam is taken off at 1200 ft in a 1500- ft deep well. That is, the formation thickness is taken to be 300 ft. Other steam splitting ratios could have been considered, but it was not done in view of computer time limitations. The results of steam quality and pressure with time were used to carry out a steamflood simulation for the Aberfeldy reservoir conditions. Results for the assumption of a constant steam injection pressure and quality are compared with those for the steam and pressure and quality input from the wellbore simulator.

Table 6.10 lists the well data used in the simulations.

Effect of Steam Injection Rate and Flow Splitting on Steam Quality

Seventy-two runs were carried out for wellbore steam flow, half for no flow splitting, the other half for flow splitting. The results of the runs for bottomhole quality and pressure are summarized in Tables 6.11 and 6.12. The data versus depth are given in Table D.1 through D.24. Selected results are plotted in Figs. 6.96 through 6.110.

Table 6.10

CONDITIONS USED FOR WELLBORE HEAT LOSS CALCULATIONS

Pressure at Surface	260.0 psia
Atmospheric Temperature	80.0°F
Grid Points in R-Direction	5
Ratio of Radius of Grid	2.5
Time Elapsed	30.0 days
Thermal Conductivity of Annulus	0.0263
Emissivity of Tubing	0.9000
Density of Annular Fluid	0.0360 lb/ft ³
Tolerance of P	1.00 psia
Type of Flow	Production
Tubing Insulation	No
Type of Annulus Fluid	Gas
Casing Size	10.000 inch
Tubing Size	8.000 inch
Tubing Relative Roughness	0.00023
Depth	1400.0 feet
Reservoir Temperature	108.0°F
Grid Points in Z-Direction	11
Delz	140.0 feet
Deltim	3.0 days
Thermal Conductivity of Cement	0.5500
Emissivity of Casing	0.9000
Viscosity of Annular Fluid	0.0664 lbm/ft-hr
Tolerance of Q	0.010
Borehole Size	12.000 inch
Mass Flow Rate	558000.0 lb/hr
Geothermal Gradient	0.020 °F/ft
Thermal Conductivity of Earth	1.4000
Thermal Diffusivity of Earth	0.9600 ft ² /day
Specific Heat of Annular Fluids	0.2475 Btu/lb-°F
Tolerance of U	0.05

Table: 6.11
WELLBORE STEAM FLOW RUNS SUMMARY
 DEPTH 1500 FT: STEAM OFFTAKE AT 1200 FT;
 OFFTAKE RATE ONE-HALF FLOW RATE
 SURFACE QUALITY 0.80

Legend:

RN : WB RUN NUMBER

T : Time, Days

SR : Steam Rate, Bbls/Day

IP : Inj. Pressure, psia

OR : Offtake Rate, Bbls/Day

SQ : Steam Quality, Frac at 1500 FT

SP : Steam Pressure, psia at 1500 FT

RN	T	SR	IP	OR	SQ	SP
1	100	600	1500	300	0.3298	1799.85
2	300	600	1500	300	0.3454	1800.05
3	500	600	1500	300	0.3458	1800.02
4	700	600	1500	300	0.3458	1800.02
5	900	600	1500	300	0.3458	1800.02
6	1100	600	1500	300	0.3458	1800.02
7	100	1200	1500	600	0.5674	1731.56
8	300	1200	1500	600	0.5751	1731.06
9	500	1200	1500	600	0.5753	1731.05
10	700	1200	1500	600	0.5753	1731.05
11	900	1200	1500	600	0.5753	1731.05
12	1100	1200	1500	600	0.5753	1731.05
13	100	1800	1500	900	0.6453	1699.40
14	300	1800	1500	900	0.6505	1698.93
15	500	1800	1500	900	0.6506	1698.92
16	700	1800	1500	900	0.6506	1698.92
17	900	1800	1500	900	0.6506	1698.92
18	1100	1800	1500	900	0.6506	1698.92
19	100	600	1500	0	0.4779	1774.34
20	300	600	1500	0	0.4897	1773.28
21	500	600	1500	0	0.4900	1773.25
22	700	600	1500	0	0.4900	1773.25
23	900	600	1500	0	0.4900	1773.25
24	1100	600	1500	0	0.4900	1773.25
25	100	1200	1500	0	0.6402	1707.33
26	300	1200	1500	0	0.6460	1706.96
27	500	1200	1500	0	0.6461	1706.95
28	700	1200	1500	0	0.6461	1706.95
29	900	1200	1500	0	0.6461	1706.95
30	1100	1200	1500	0	0.6461	1706.95
31	100	1800	1500	0	0.6934	1679.69
32	300	1800	1500	0	0.6972	1679.49
33	500	1800	1500	0	0.6973	1679.49
34	700	1800	1500	0	0.6973	1679.49
35	900	1800	1500	0	0.6973	1679.49
36	1100	1800	1500	0	0.6973	1679.49

Table: 6.12
WELLBORE STEAM FLOW RUNS SUMMARY
 DEPTH 1500 FT: STEAM OFFTAKE AT 1200 FT;
 OFFTAKE RATE ONE-HALF FLOW RATE
 SURFACE QUALITY 0.80

Legend:

RN : WB RUN NUMBER

T : Time, Days

SR : Steam Rate, Bbls/Day

IP : Inj. Pressure, psia

OR : Offtake Rate, Bbls/Day

SQ : Steam Quality, Frac at 1500 FT

SP : Steam Pressure, psia at 1500 FT

RN	T	SR	IP	OR	SQ	SP
37	100	600	750	300	0.4603	1000.17
38	300	600	750	300	0.4714	999.31
39	500	600	750	300	0.4716	999.29
40	700	600	750	300	0.4716	999.29
41	900	600	750	300	0.4716	999.29
42	1100	600	750	300	0.4716	999.29
43	100	1200	750	600	0.4716	999.29
44	300	1200	750	600	0.6322	936.22
45	500	1200	750	600	0.6375	935.93
46	700	1200	750	600	0.6376	935.92
47	900	1200	750	600	0.6376	935.92
48	1100	1200	750	600	0.6376	935.92
49	100	1800	750	900	0.6376	935.92
50	300	1800	750	900	0.6878	910.38
51	500	1800	750	900	0.6913	910.24
52	700	1800	750	900	0.6914	910.23
53	900	1800	750	900	0.6914	910.23
54	1100	1800	750	900	0.6914	910.23
55	100	600	750	0	0.6914	910.23
56	300	600	750	0	0.5672	970.33
57	500	600	750	0	0.5753	969.68
58	700	600	750	0	0.5755	969.67
59	900	600	750	0	0.5755	969.67
60	1100	600	750	0	0.5755	969.67
61	100	1200	750	0	0.5755	969.67
62	300	1200	750	0	0.6838	915.68
63	500	1200	750	0	0.6878	915.49
64	700	1200	750	0	0.6879	915.49
65	900	1200	750	0	0.6879	915.49
66	1100	1200	750	0	0.6879	915.49
67	100	1800	750	0	0.6879	915.49
68	300	1800	750	0	0.7218	895.10
69	500	1800	750	0	0.7244	895.00
70	700	1800	750	0	0.7244	895.00
71	900	1800	750	0	0.7244	895.00
72	1100	1800	750	0	0.7244	895.00

Figures 6.96 through 6.101 show steam quality versus depth, for injection time of 100, 300, 500, 700, 900, and 1100 days, respectively. In each figure, quality is plotted for steam injection rates of 600, 1200, and 1800 B/D; for each rate there are two branches, one for zero offtake, and the other one for one-half steam offtake at 1200 ft. It is seen that the steam quality below the point of offtake is considerably lower than that in the absence of offtake. Furthermore, the relative quality drop becomes smaller as the steam injection rate increases. The plots for different times show that this trend persists, however, steam quality at all points increases with time. The reason for this behaviour is that when steam is taken off at a particular point in the wellbore, the remaining steam flows at a reduced velocity, with approximately the same temperature. Thus the heat loss rate, which is dependent on temperature is nearly the same, and it now acts on a reduced steam flow rate, resulting in a considerable quality drop. The situation is more complex, because steam pressure is also changing, causing a change in temperature, but this effect is not as important as the change in the steam flow, i.e. heat flow rate. It can be expected that at higher steam flow rates, the relative heat flow is increased, and hence the above effects are less important, as the curves in Fig. 6.96 through 6.101 show. It can be concluded that the steam quality is likely to drop below the point of offtake in a multiple layer steam injection well. The amount of drop will depend on the steam injection rate, the steam offtake rate, and steam pressure. Other variables of importance not examined in this work are: the type of well completion, heat loss reduction technique used, characteristics of the surrounding rocks, and the effect of a fluid level in the wellbore, which would also tend to restrict the uniform distribution of steam over the injection interval.

Effect of Steam Injection Rate and Flow Splitting on Steam Pressure

Figures 6.102 through 6.107 show graphs of steam pressure versus depth, for times of 100, 300, 500, 700, 900 and 1100 days, respectively. In each case, three curves are shown for steam injection rates of 600, 1200 and 1800 B/D. Each curve has two branches,

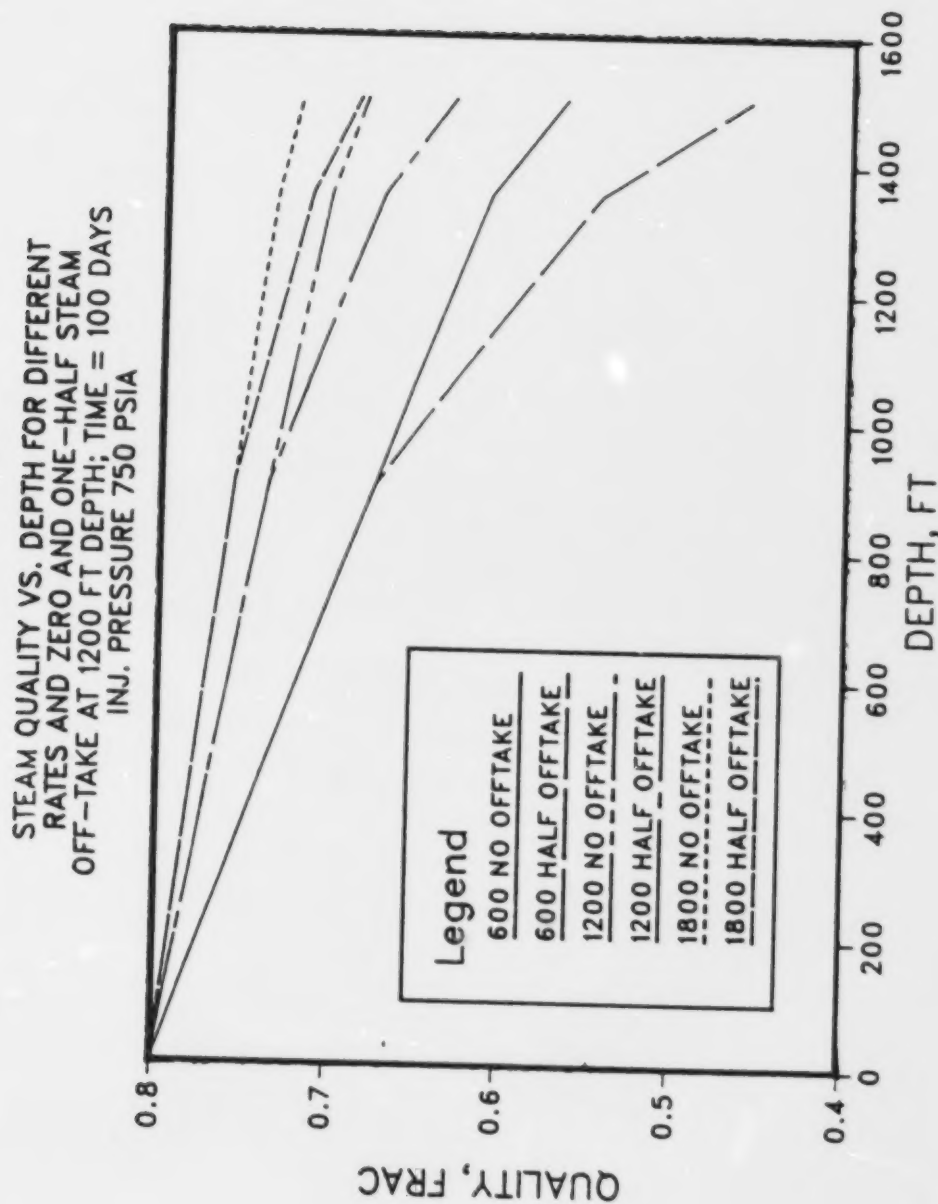


Figure 6.96 Wellbore Steam Quality for Zero and One-Half Offtakes (Time = 100 days)

STEAM QUALITY VS. DEPTH FOR DIFFERENT
RATES AND ZERO AND ONE-HALF STEAM
OFF-TAKE AT 1200 FT DEPTH; TIME = 300 DAYS
INJ. PRESSURE 750 PSIA

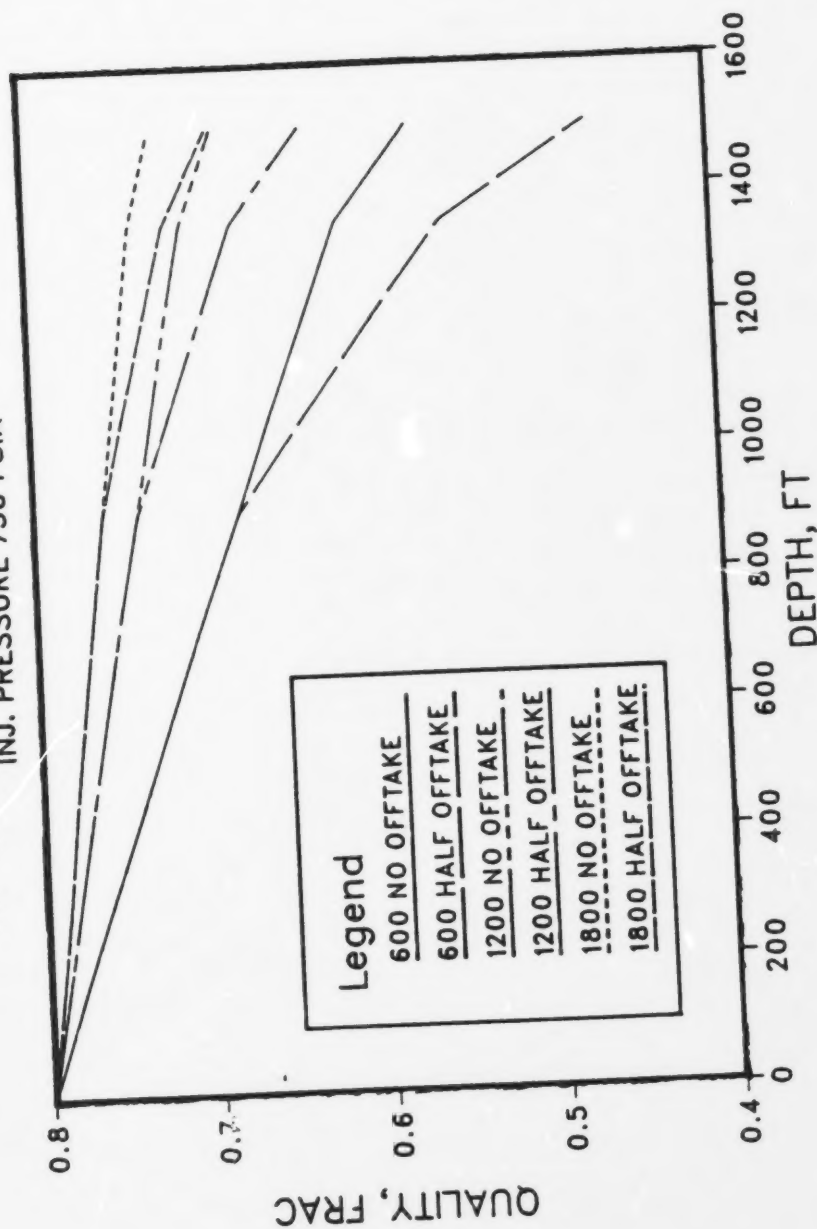


Figure 6.97 Wellbore Steam Quality for Zero and One-Half Offtakes (Time = 300 days)

STEAM QUALITY VS. DEPTH FOR DIFFERENT
RATES AND ZERO AND ONE-HALF STEAM
OFF-TAKE AT 1200 FT DEPTH; TIME = 500 DAYS
INJ. PRESSURE 750 PSIA

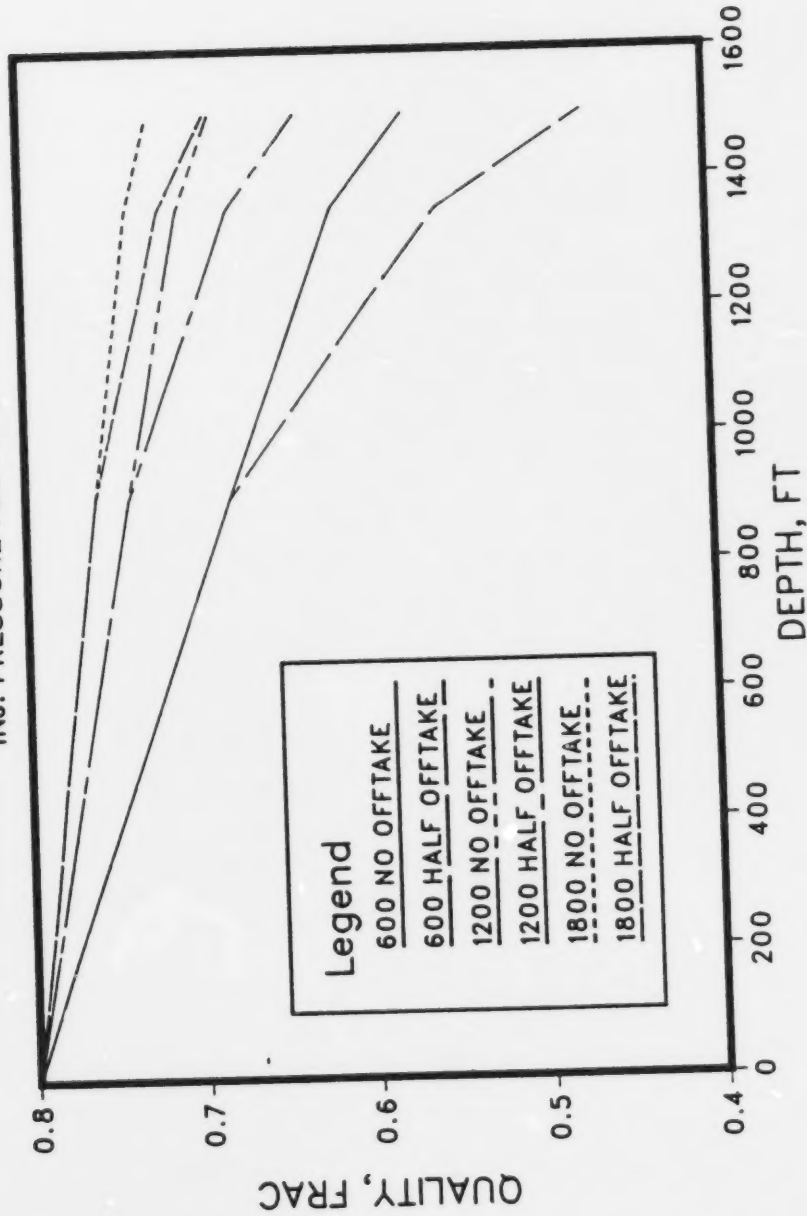


Figure 6.98 Wellbore Steam Quality for Zero and One-Half Offtakes (Time = 500 days)

STEAM QUALITY VS. DEPTH FOR DIFFERENT
 RATES AND ZERO AND ONE-HALF STEAM
 OFF-TAKE AT 1200 FT DEPTH; TIME = 700 DAYS
 INJ. PRESSURE 750 PSIA

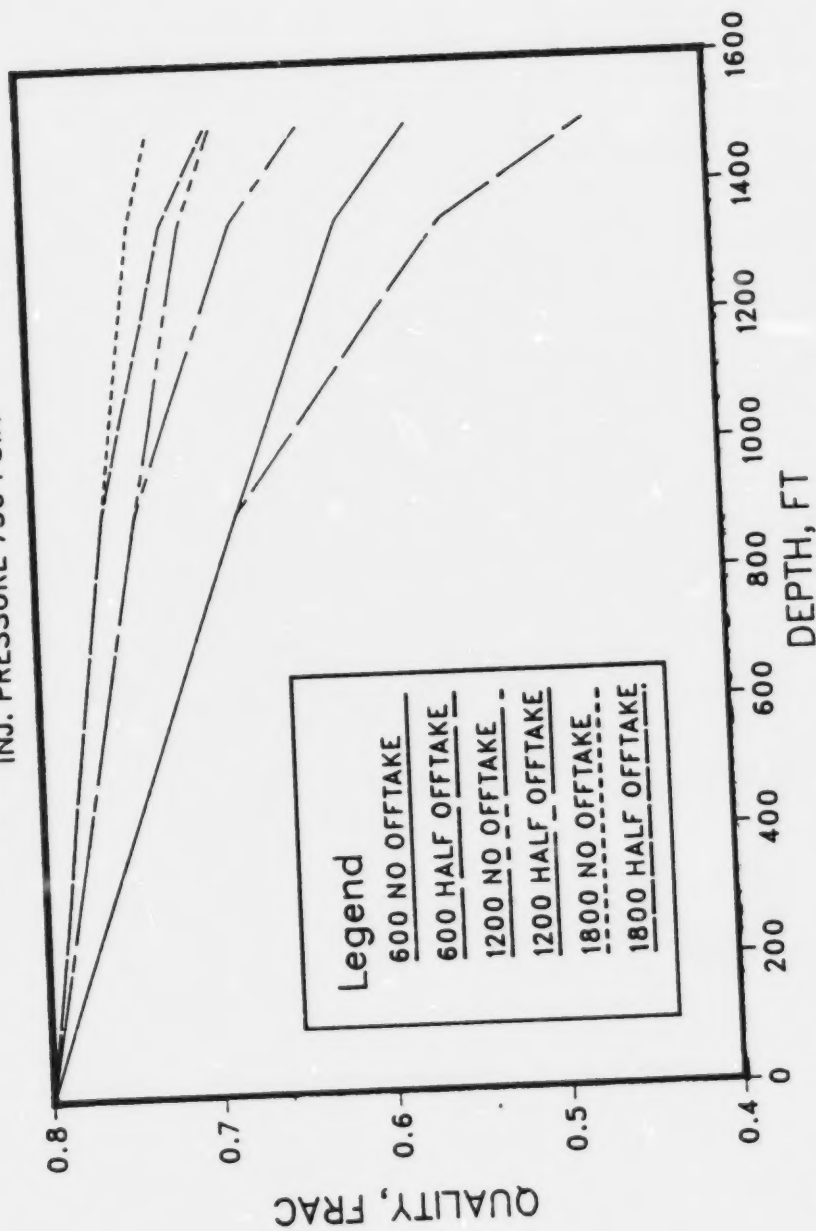


Figure 6.99 Wellbore Steam Quality for Zero and One-Half Offtakes (Time = 700 days)

STEAM QUALITY VS. DEPTH FOR DIFFERENT
RATES AND ZERO AND ONE-HALF STEAM
OFF-TAKE AT 1200 FT DEPTH; TIME = 900 DAYS
INJ. PRESSURE 750 PSIA

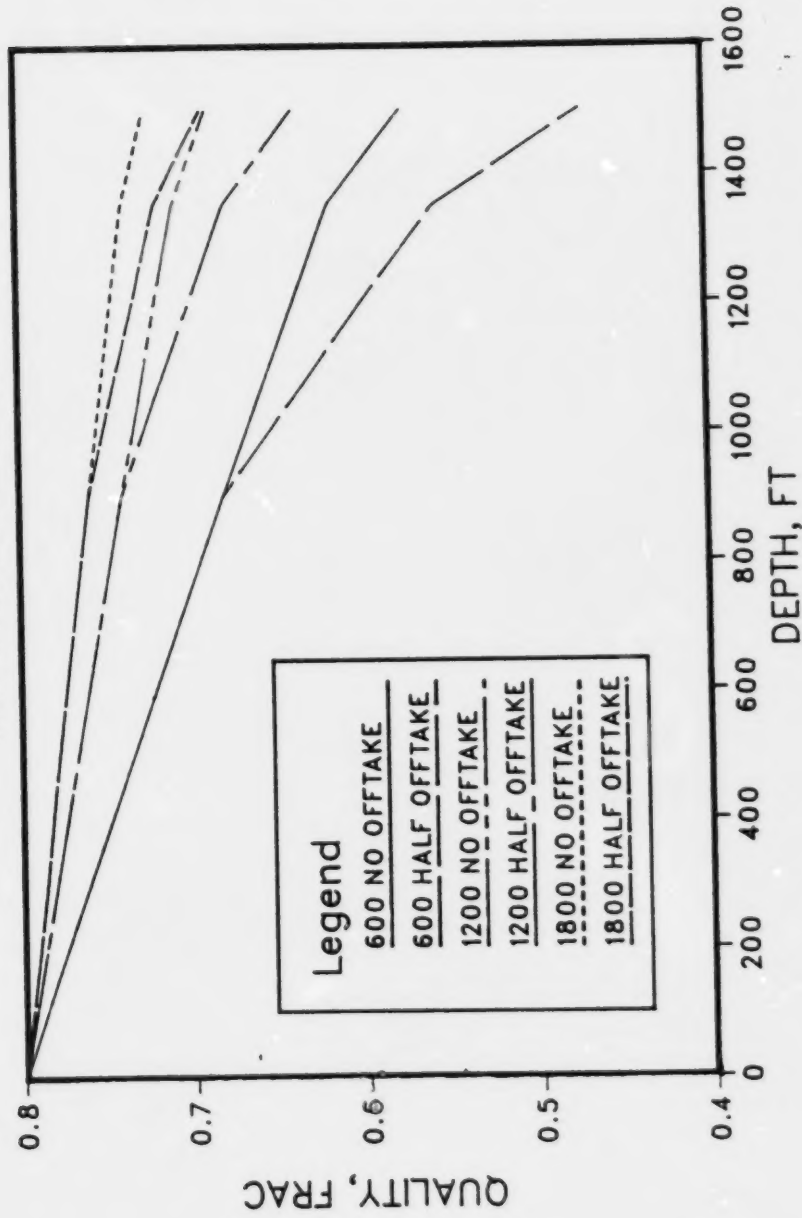


Figure 6.100 Wellbore Steam Quality for Zero and One-Half Offtakes (Time = 900 days)

STEAM QUALITY VS. DEPTH FOR DIFFERENT
RATES AND ZERO AND ONE-HALF STEAM
OFF-TAKE AT 1200 FT DEPTH; TIME = 1100 DAYS
INJ. PRESSURE 750 PSIA

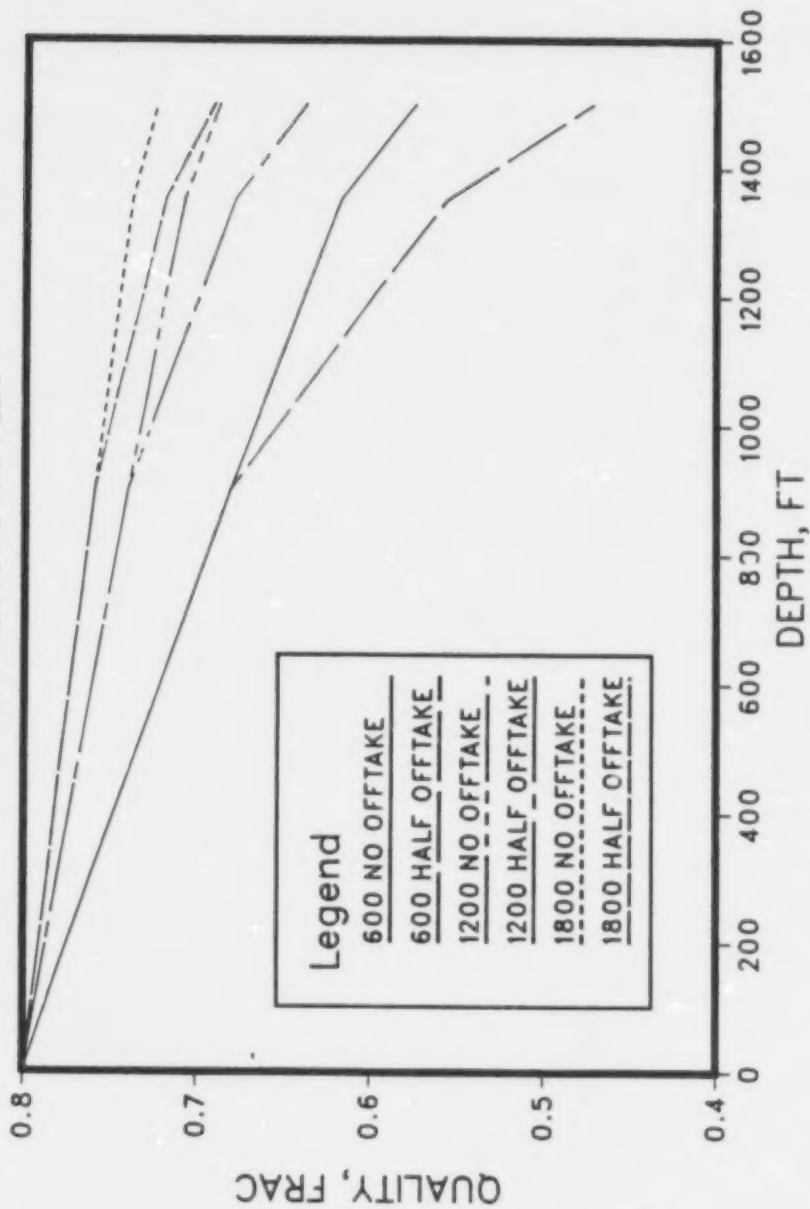


Figure 6.101 Wellbore Steam Quality for Zero and One-Half Offtakes (Time = 1100 days)

STEAM QUALITY VS. DEPTH FOR DIFFERENT
 RATES AND ZERO AND ONE-HALF STEAM
 OFF-TAKE AT 1200 FT DEPTH; TIME = 100 DAYS
 INJ. PRESSURE 750 PSIA

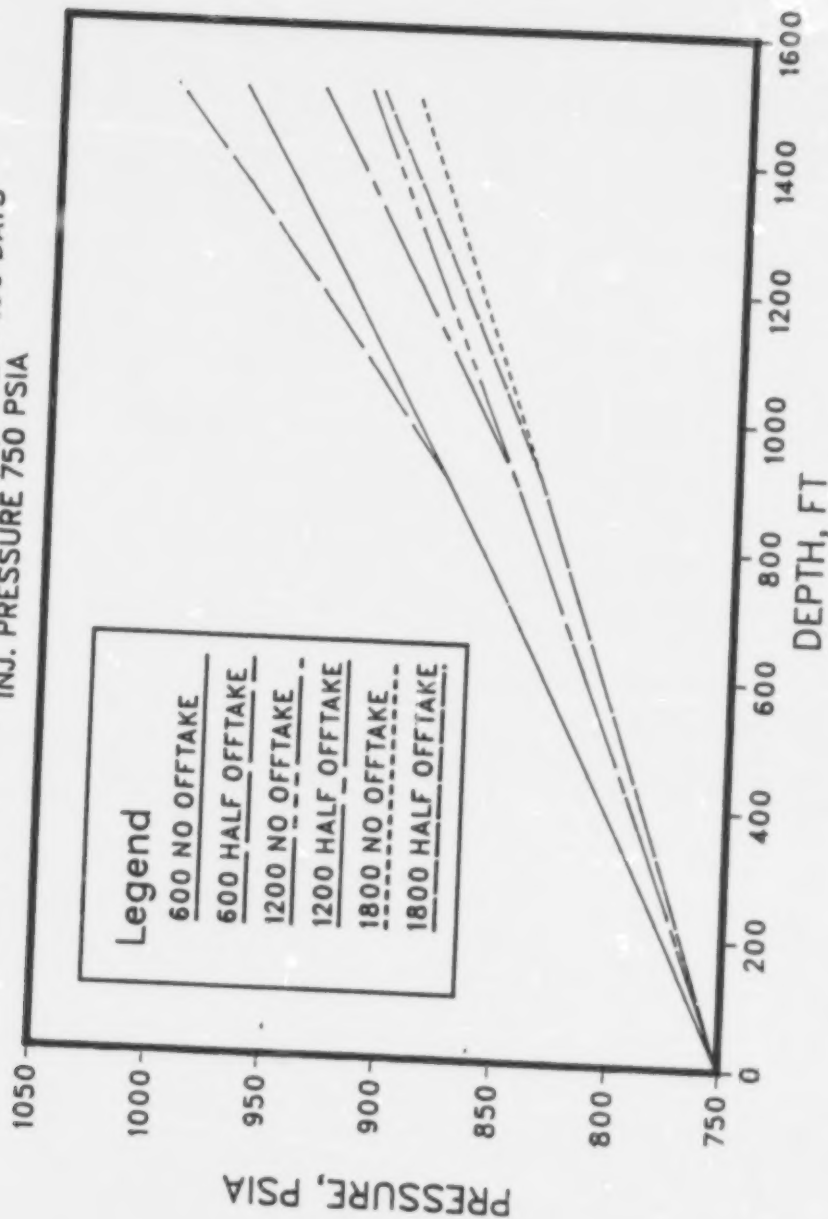


Figure 6.102 Wellbore Steam Pressure for Zero and One-Half Offtakes (Time = 100 days)

STEAM QUALITY VS. DEPTH FOR DIFFERENT
RATES AND ZERO AND ONE-HALF STEAM
OFF-TAKE AT 1200 FT DEPTH; TIME = 300 DAYS
INJ. PRESSURE 750 PSIA

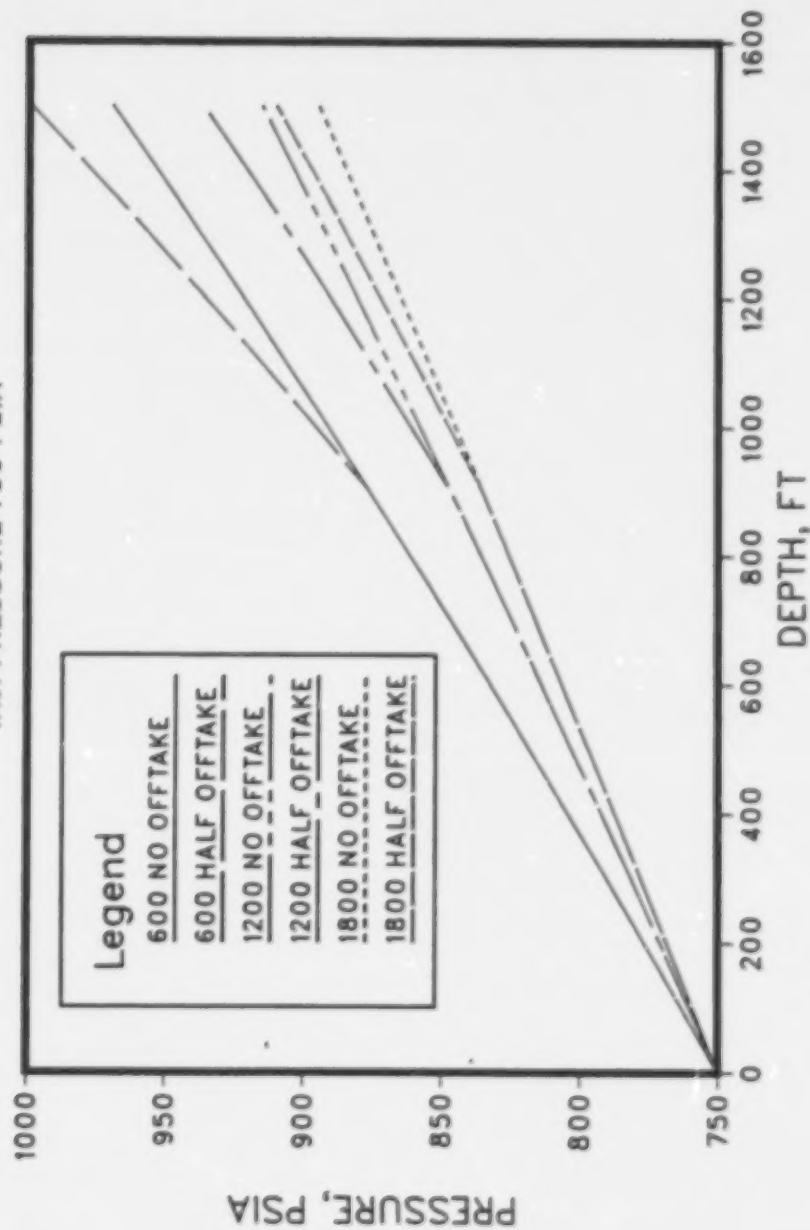


Figure 6.103 Wellbore Steam Pressure for Zero and One-Half Offtakes (Time = 300 days)

STEAM QUALITY VS. DEPTH FOR DIFFERENT
RATES AND ZERO AND ONE-HALF STEAM
OFF-TAKE AT 1200 FT DEPTH; TIME = 500 DAYS
INJ. PRESSURE 750 PSIA

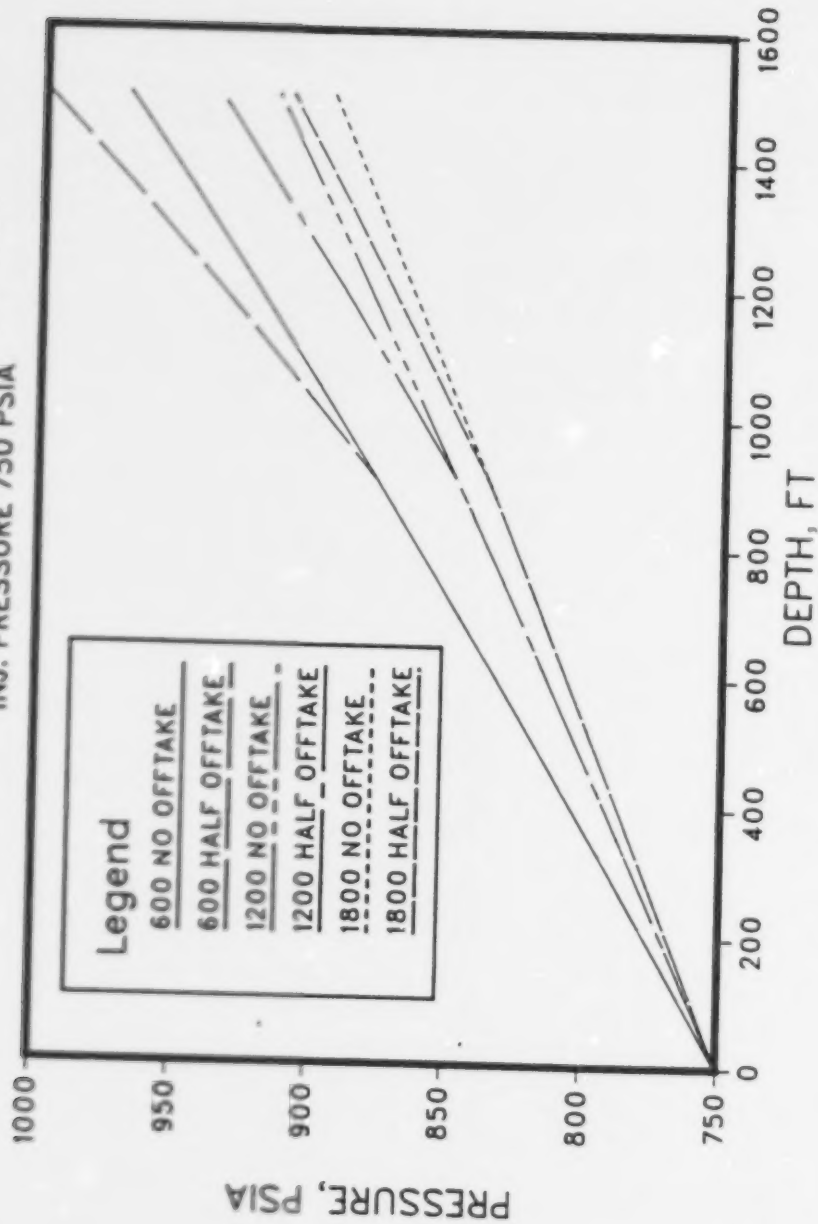


Figure 6.104 Wellbore Steam Pressure for Zero and One-Half Offtakes (Time = 500 days)

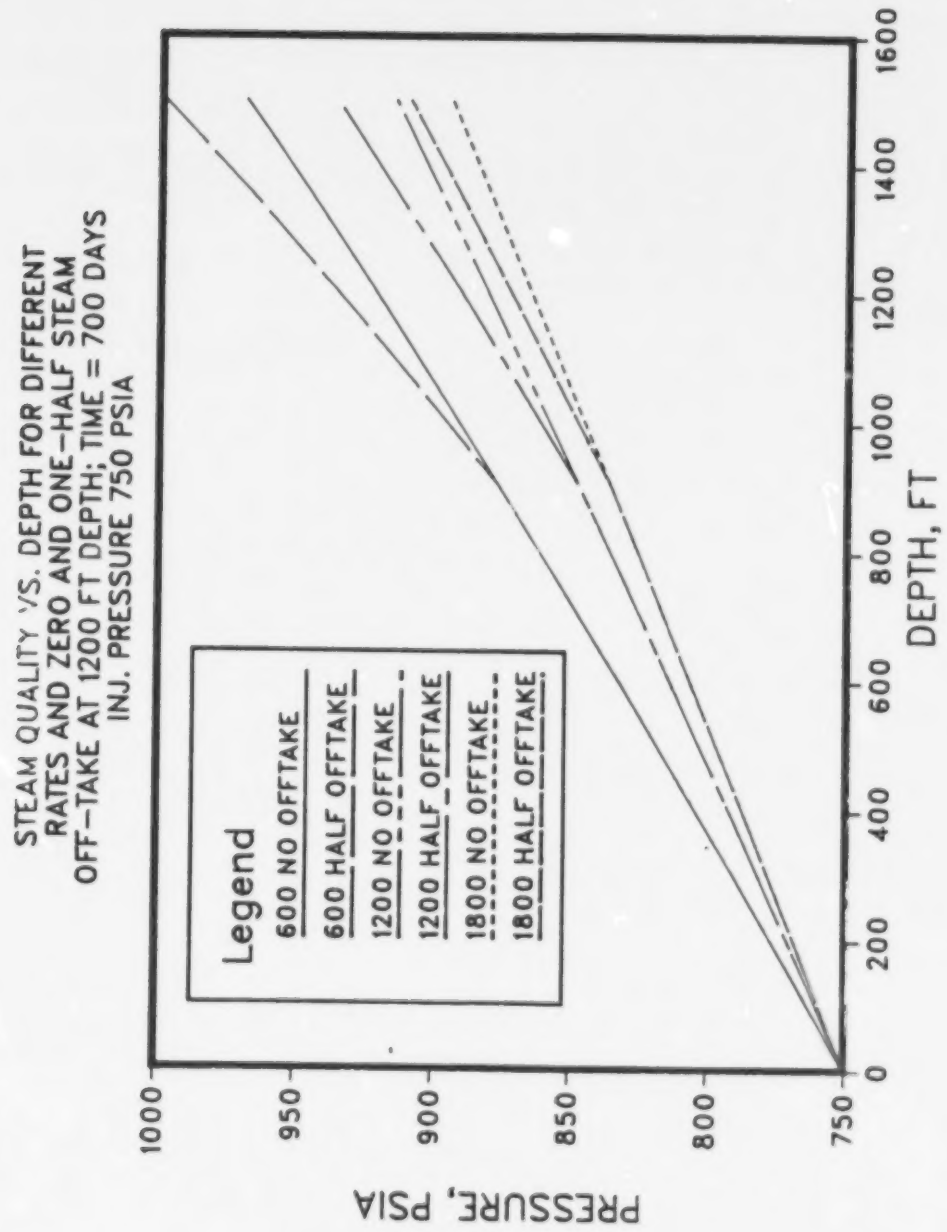


Figure 6.105 Wellbore Steam Pressure for Zero and One-Half Offtakes (Time = 700 days)

STEAM QUALITY VS. DEPTH FOR DIFFERENT
 RATES AND ZERO AND ONE-HALF STEAM
 OFF-TAKE AT 1200 FT DEPTH; TIME = 900 DAYS
 INJ. PRESSURE 750 PSIA

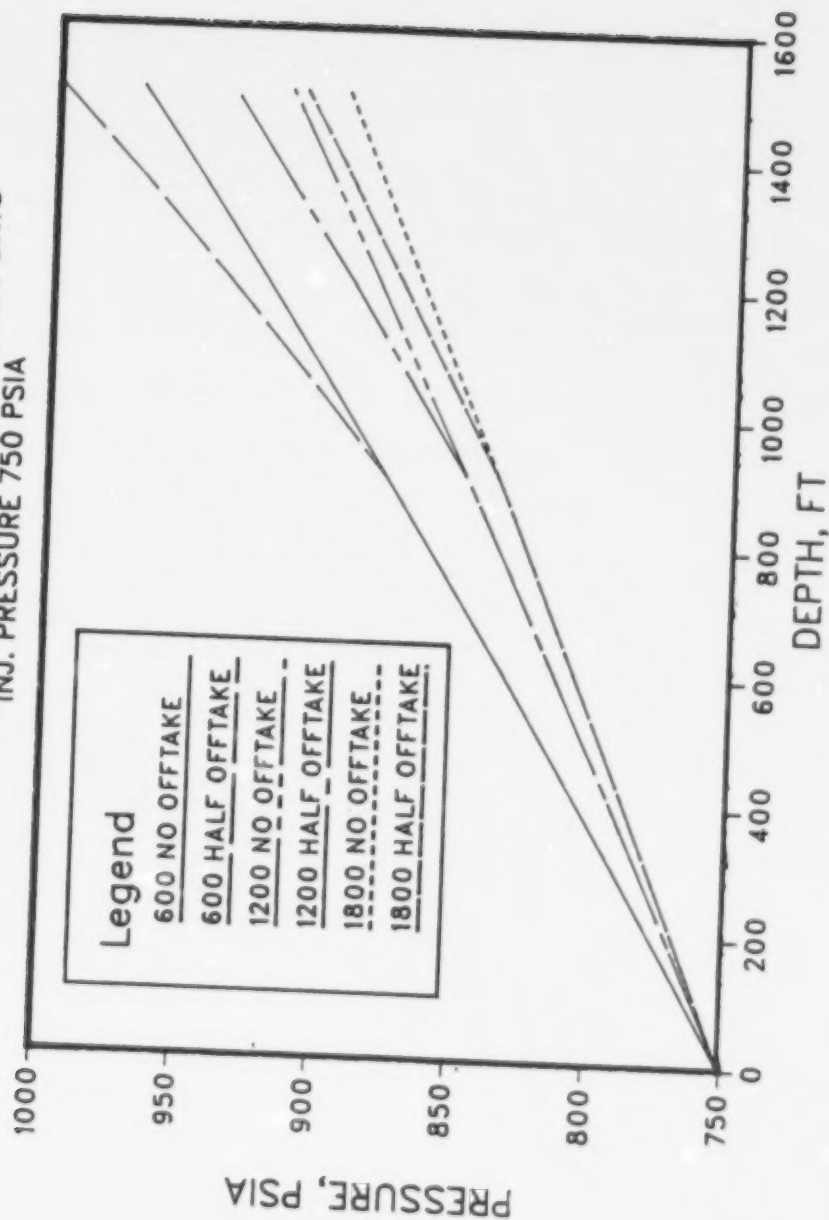


Figure 6.106 Wellbore Steam Pressure for Zero and One-Half Offtakes (Time = 900 days)

STEAM QUALITY VS. DEPTH FOR DIFFERENT
RATES AND ZERO AND ONE-HALF STEAM
OFF-TAKE AT 1200 FT DEPTH; TIME = 1100 DAYS
INJ. PRESSURE 750 PSIA

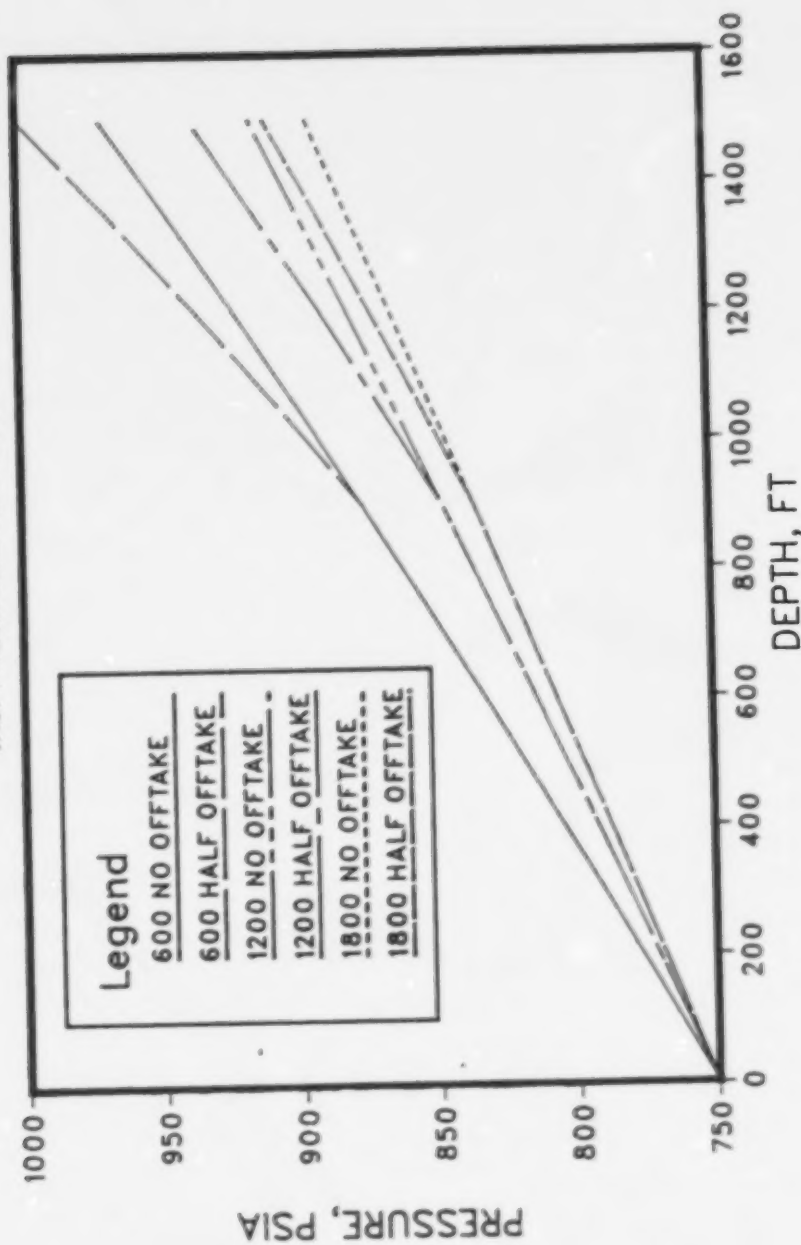


Figure 6.107 Wellbore Steam Pressure for Zero and One-Half Offtakes (Time = 1100 days)

one corresponding to a zero offtake, the other one corresponding to the offtake rate that is one-half of the steam rate. It is seen that in all cases, the steam pressures below the offtake point (1200 ft) are higher than those in the absence of offtake. This is due to the fact that steam quality decreases below the offtake point (as shown in the previous section), leading to an increase in the hydrostatic head, which causes an increase in steam pressure. This is further helped by the reduced frictional pressure drop due to the reduced velocity of steam below the offtake point. This effect becomes less important as the steam injection rate increases. In an actual multilayer injection operation, the situation would be more complex than the one described here. The increased steam pressure expected below the offtake point will lead to an increase in the steam flow rate below the offtake point with time. As a result, it is possible that the steam flow rate at the intermediate offtake point would continue to drop with time, and eventually reach some equilibrium value different from the design rate. It may be concluded that steam injection wells with multiple offtakes can be difficult to control as far as the steam inflow into individual layers is concerned.

Figures 6.108 and 6.109 summarize the results for bottomhole (1500 ft) steam quality, for offtake at 1200 ft, and for the two steam injection pressures considered (1500 and 750 psia). Again it is seen that the bottomhole qualities are lower when there is steam offtake. But the difference between the curves for increasing steam injection rates, or increasing steam injection pressures decreases, for reasons given above. It is evident that the effect of offtake examined here is important, and should be taken into account. Steam injection simulations carried out at the present time neglect steam quality changes in multilayer injection.

Temperature Distribution in the Surrounding Rock

A secondary feature of interest is the temperature distribution in the formation surrounding the wellbore, when multiple steam offtakes are employed. It is recalled that in the present work, the temperature distribution in the surrounding formation was calculated

WELLBORE STEAM FLOW RUNS SUMMARY
DEPTH 1500 FT; STEAM OFFTAKE AT 1200 FT
SURFACE QUALITY 0.80
PRESSURE = 1500 PSIA

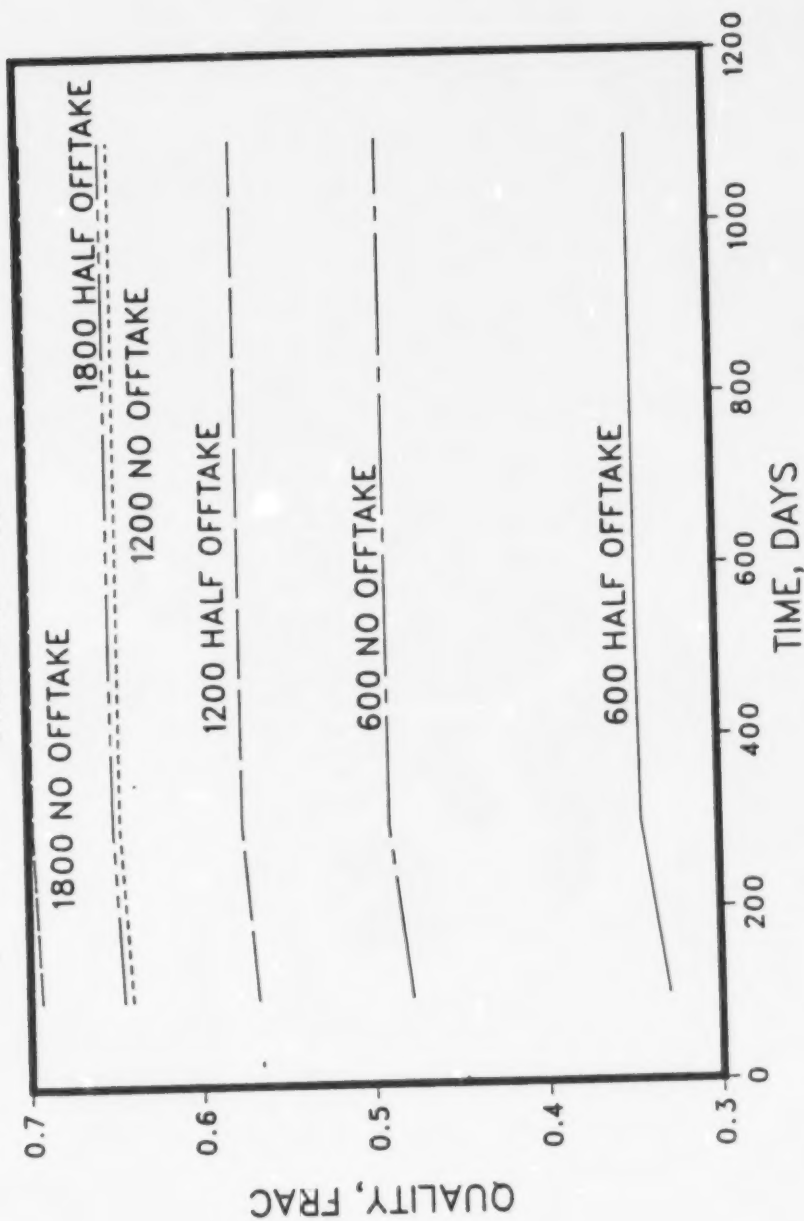


Figure 6.108 Wellbore Steam Quality vs. Time, for Surface Steam Pressure of 750 psia

WELLBORE STEAM FLOW RUNS SUMMARY
 DEPTH 1500 FT; STEAM OFFTAKE AT 1200 FT
 SURFACE QUALITY 0.80
 PRESSURE = 750 PSIA

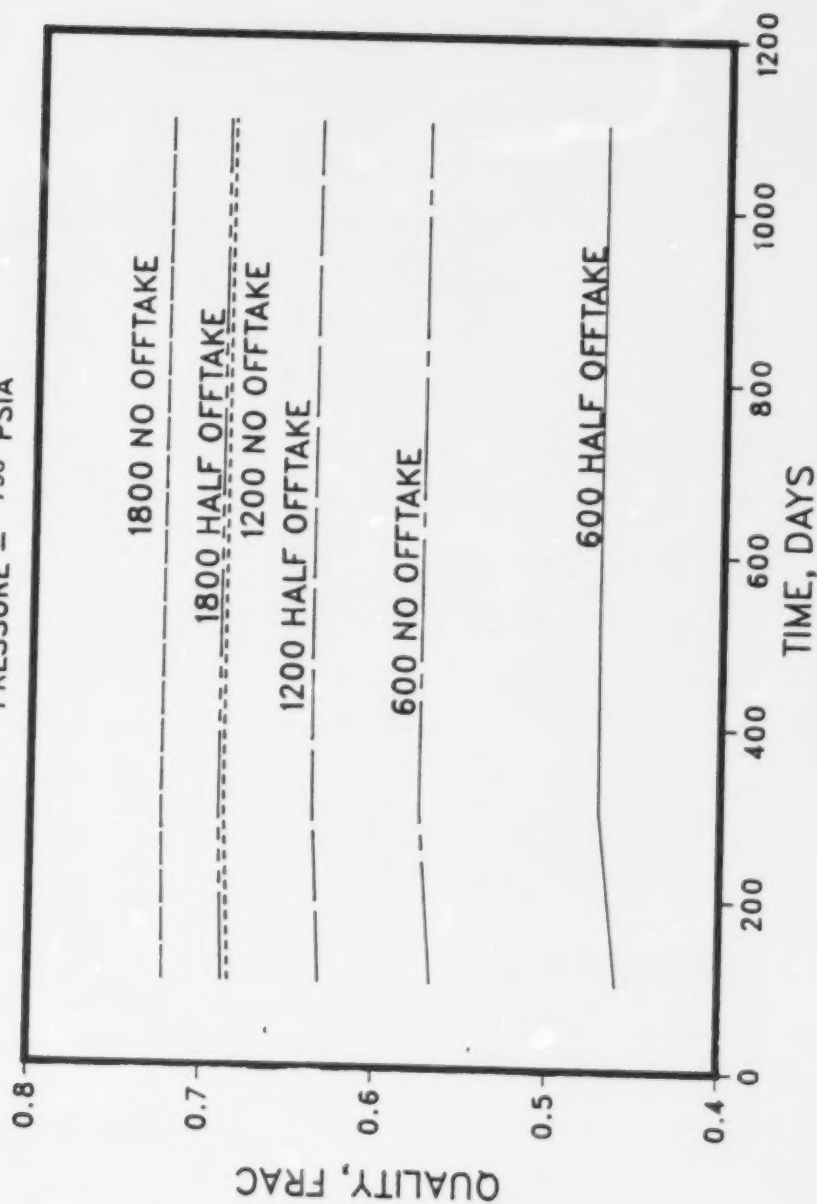


Figure 6.109 Wellbore Steam Quality vs. Time, for Surface Steam Pressure of 1500 psia

by the solution of the radial heat flow equation. It is thus expected that the temperature distribution in the formation will depend on the steam temperature in the wellbore. The temperature distribution was found to be relatively insensitive to offtake, and depends more on the injection time. Figure 110 shows the temperature distribution at a depth of 1200 ft at two different times.

Effect of Varying Steam Quality and Pressure on Steamflood Performance

Given a wellbore model such as developed here, it is possible to carry out a wide variety of coupled wellbore-reservoir studies. For the purpose of showing the effect of varying steam quality across the injection interval, one simulation of the Aberfeldy reservoir was carried out, where the wellbore steam quality and pressure for the 750 psia steam injection pressure and 600 B/D steam injection rate (CWE) history discussed above was used as a function of time. The remaining data were the same as used in the steam runs discussed previously.

Figures 6.111 through 6.118 show the oil/water production rates, water-oil ratio, and cumulative oil-steam ratio, and oil recovery, respectively, all versus cumulative steam injected, for the case of a uniform steam pressure and quality, and for variable values. The detailed production histories are shown in Tables 6.13 and 6.14, respectively. It is seen that the oil recovery is higher (42% vs. 28%) in the case of the uniform steam quality and pressure (in both layers, as well as in time) than that in the more realistic case. The main reason is that in the latter case, less dry steam is being injected in the lower part of the formation. However, the pressure is higher, and more hot water is going into the lower layer. On the whole, it can be said that the assumption of a constant steam quality over a multiple offtake injection tubing would give optimistic estimates of oil recovery.

RATE = 600 B/D
INJ. PRESSURE 750 PSIA

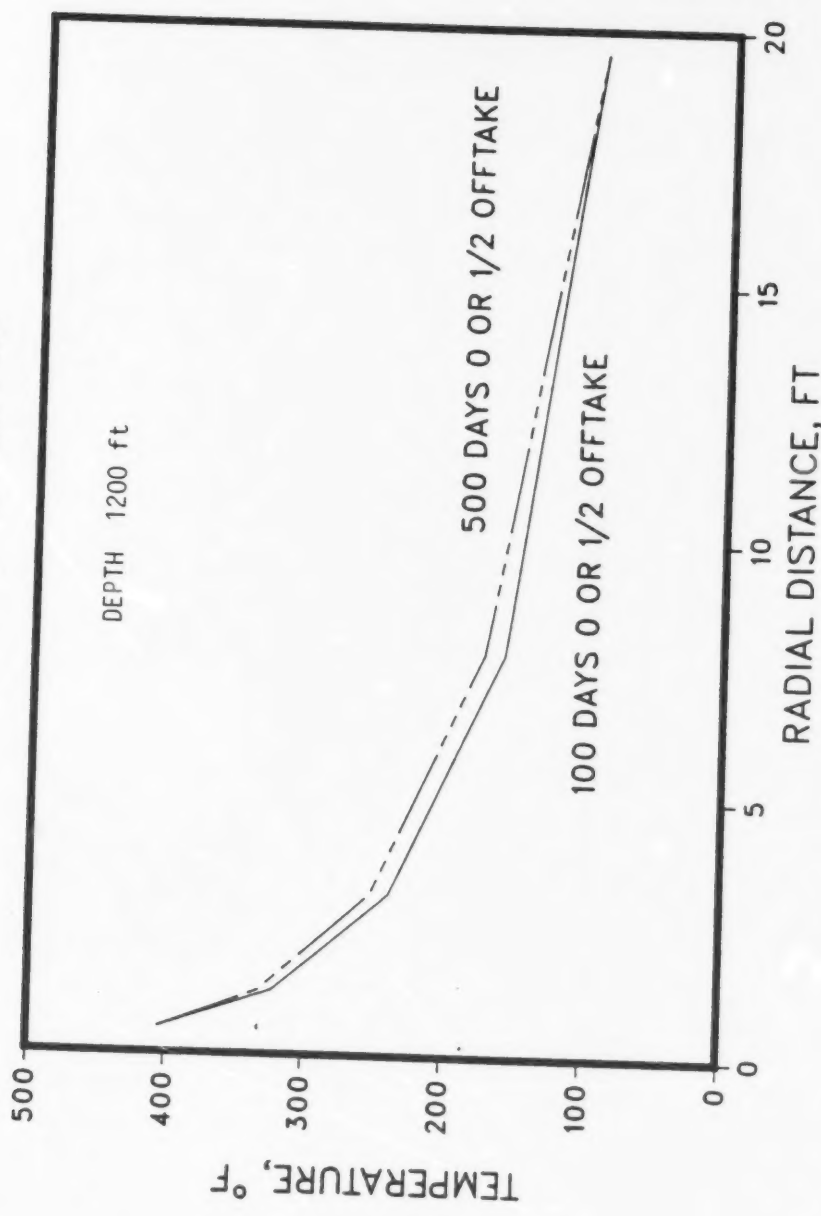


Figure 6.110 Temperature Distribution Around the Wellbore at 100 and 500 days

ABRWBO SPEC RUN FORM WELLBRE ABERFELDY
CONST QLTY, P; NO BOTTOM WATER

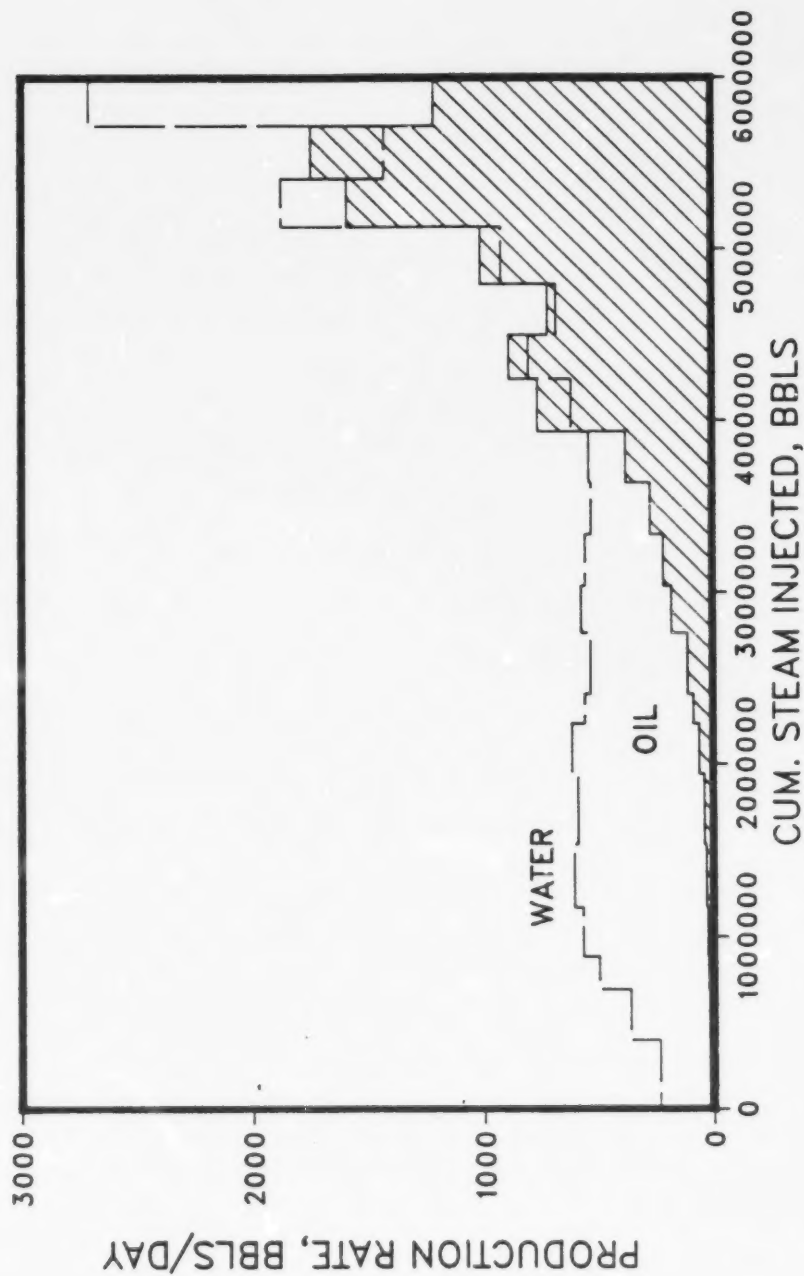


Figure 6.111 Production History for Steam Injection with a Uniform Steam Quality in the Wellbore, with Steam Offtake at Two Points

ABRWBO SPEC RUN FOR WELLBRE ABERFELDY
CONST QLTY, P; NO BOTTOM WATER

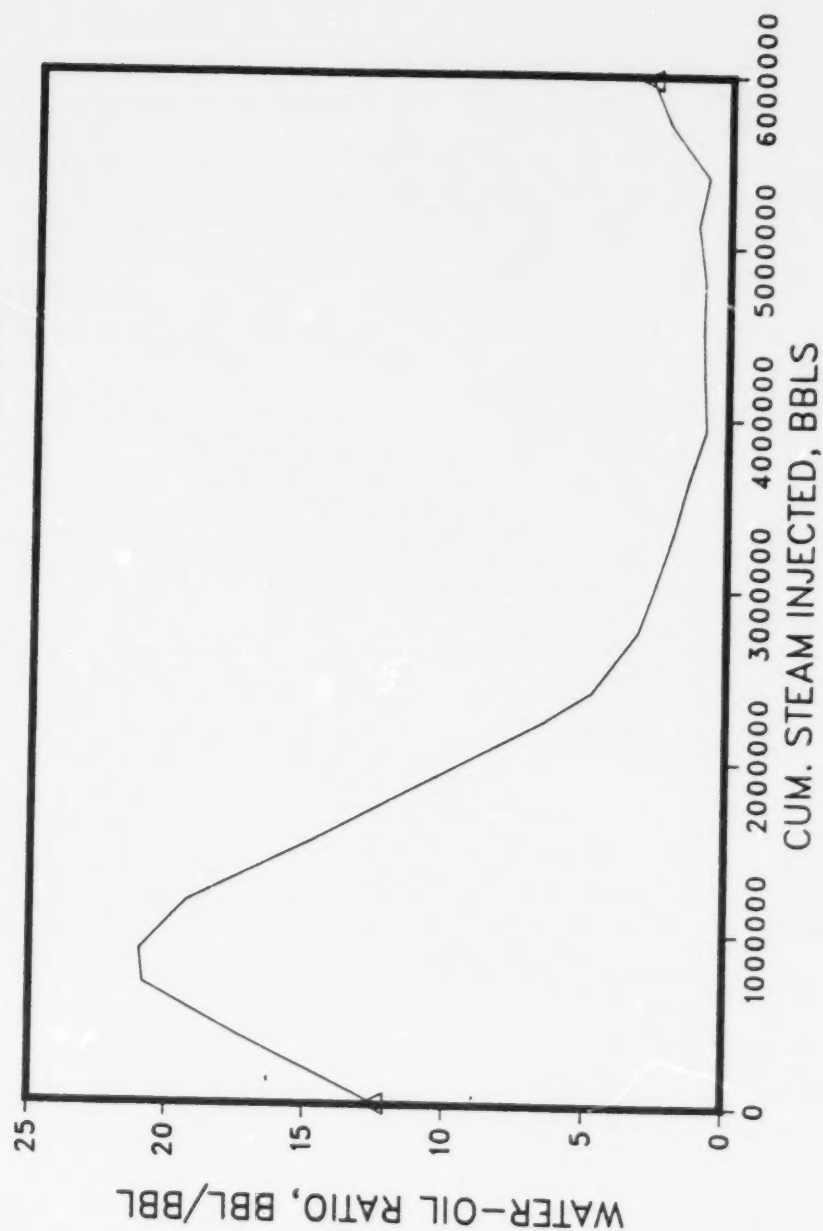


Figure 6.112 Water-Oil Ratio for Steam Injection with a Uniform Steam Quality in the Wellbore, with Steam Offtake at Two Points

ABRWB0 SPEC RUN FOR WELLBRE ABERFELDY
CONST QLTY, P; NO BOTTOM WATER

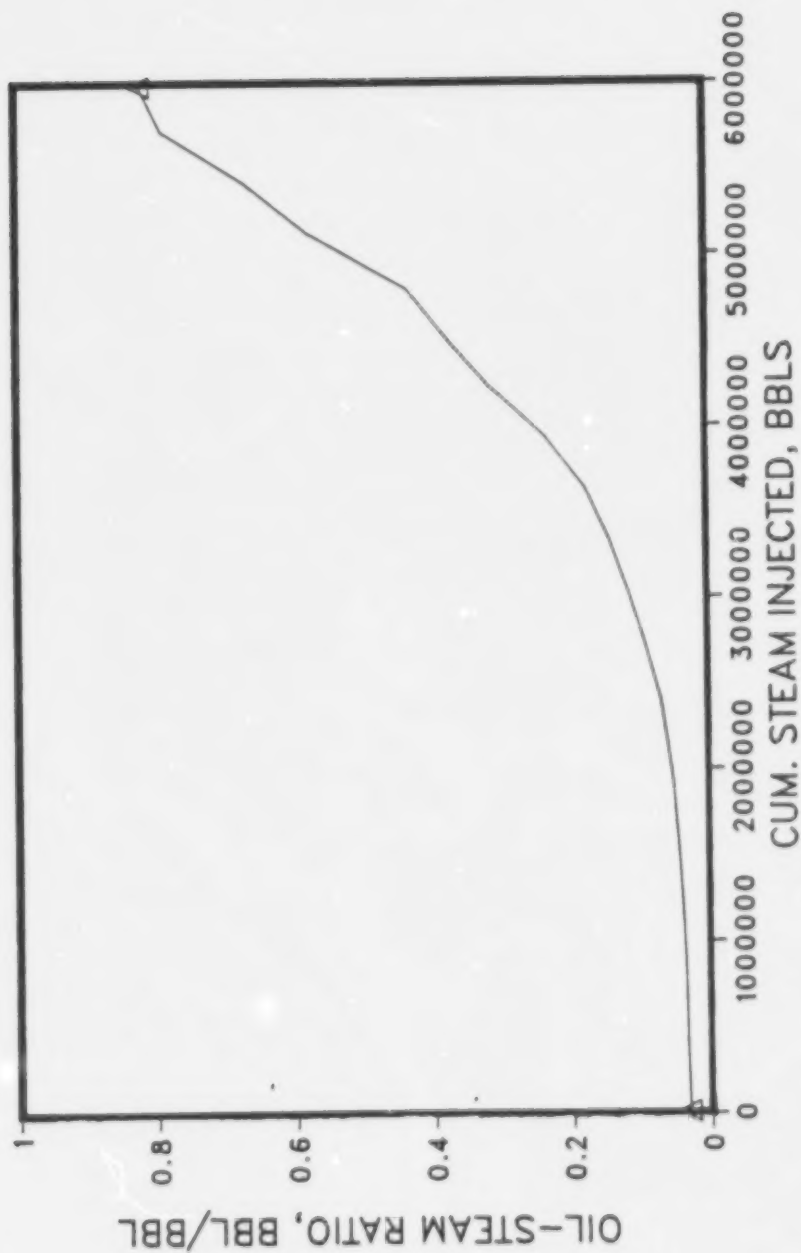


Figure 6.113 Oil-Steam Ratio for Steam Injection with a Uniform Steam Quality in the Wellbore, with Steam Offtake at Two Points

ABRWB0 SPEC RUN FOR WELLBRE ABERFELDY
CONST QLTY, P; NO BOTTOM WATER

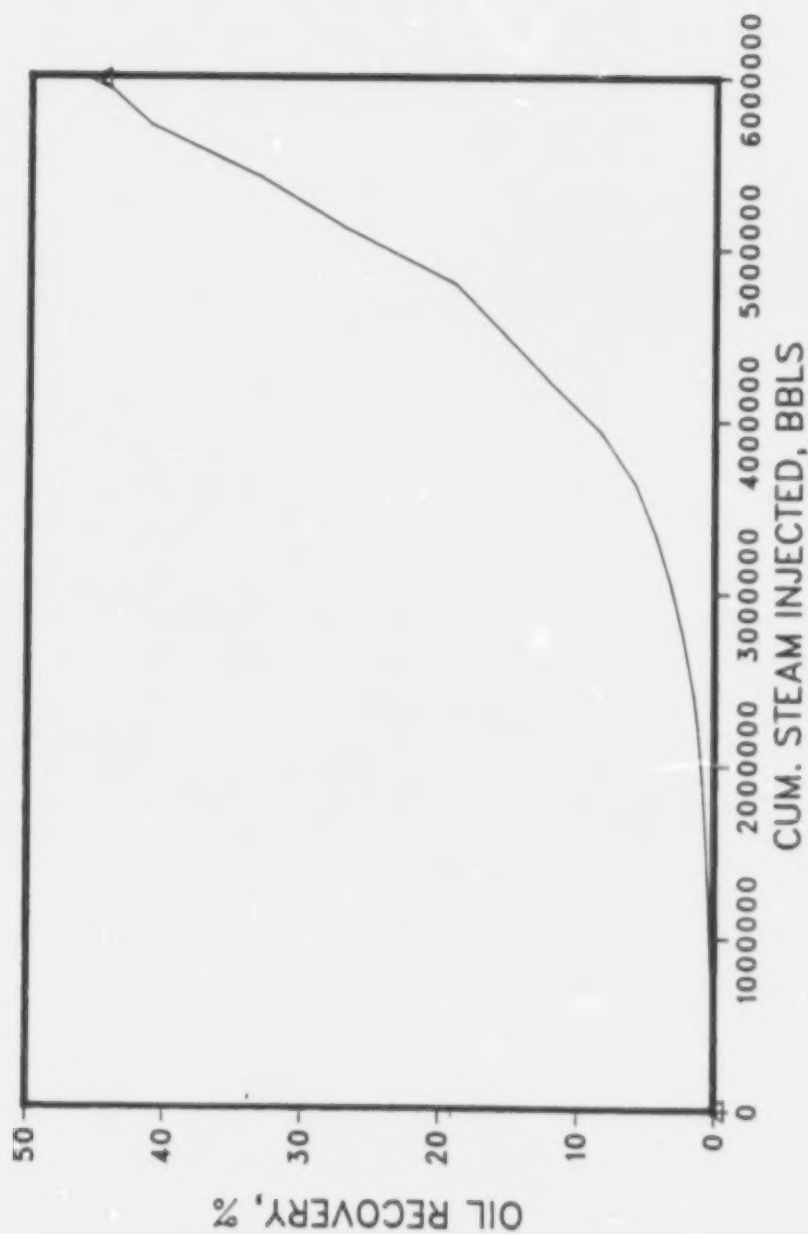


Figure 6.114 Oil Recovery for Steam Injection with a Uniform Steam Quality in the Wellbore, with Steam Offtake at Two Points

ABRWB1 SPEC RUN FORM WELLBRE ABERFELDY
VARIABLE QLTY, P; NO BOTTOM WATER

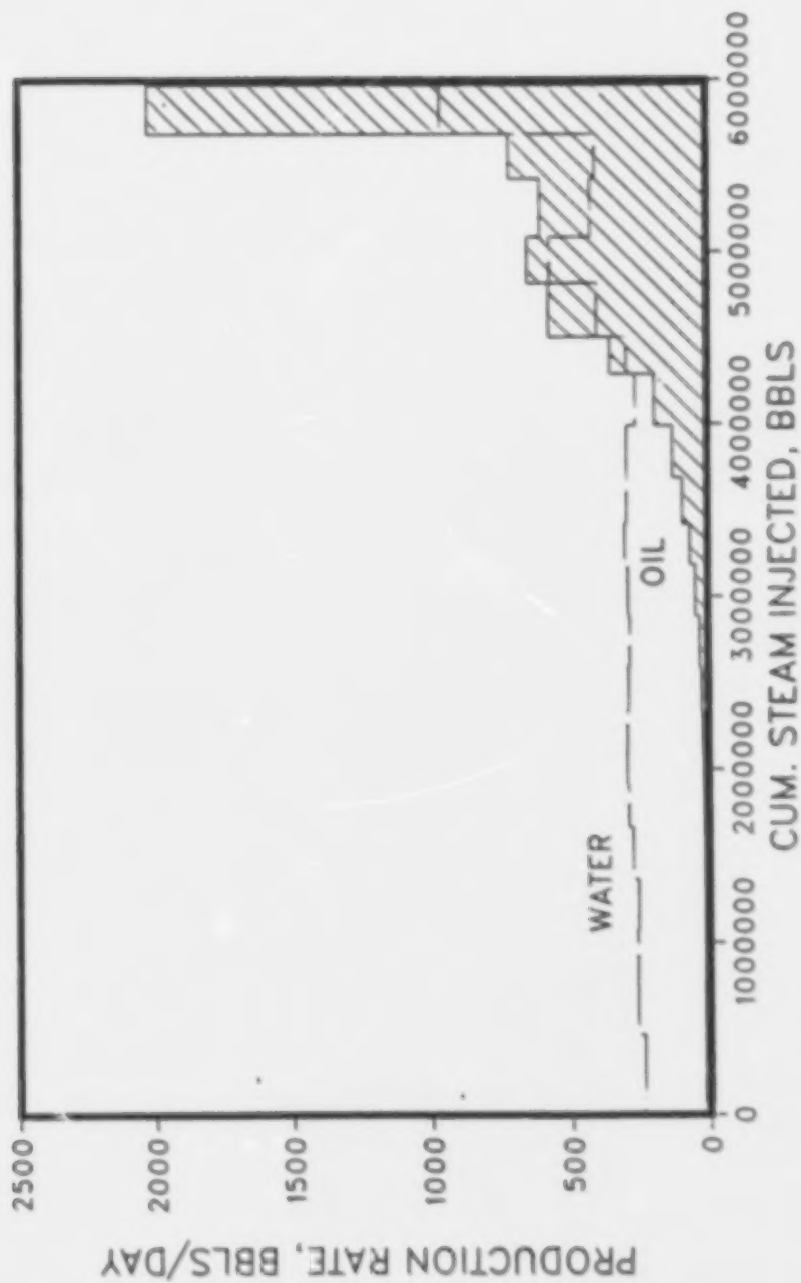


Figure 6.115 Production History for Steam Injection with a Variable Steam Quality in the Wellbore, with Steam Offtake at Two Points

ABRWB1 SPEC RUN FOR WELLBRE ABERFELDY
VARIABLE QLTY, P; NO BOTTOM WATER

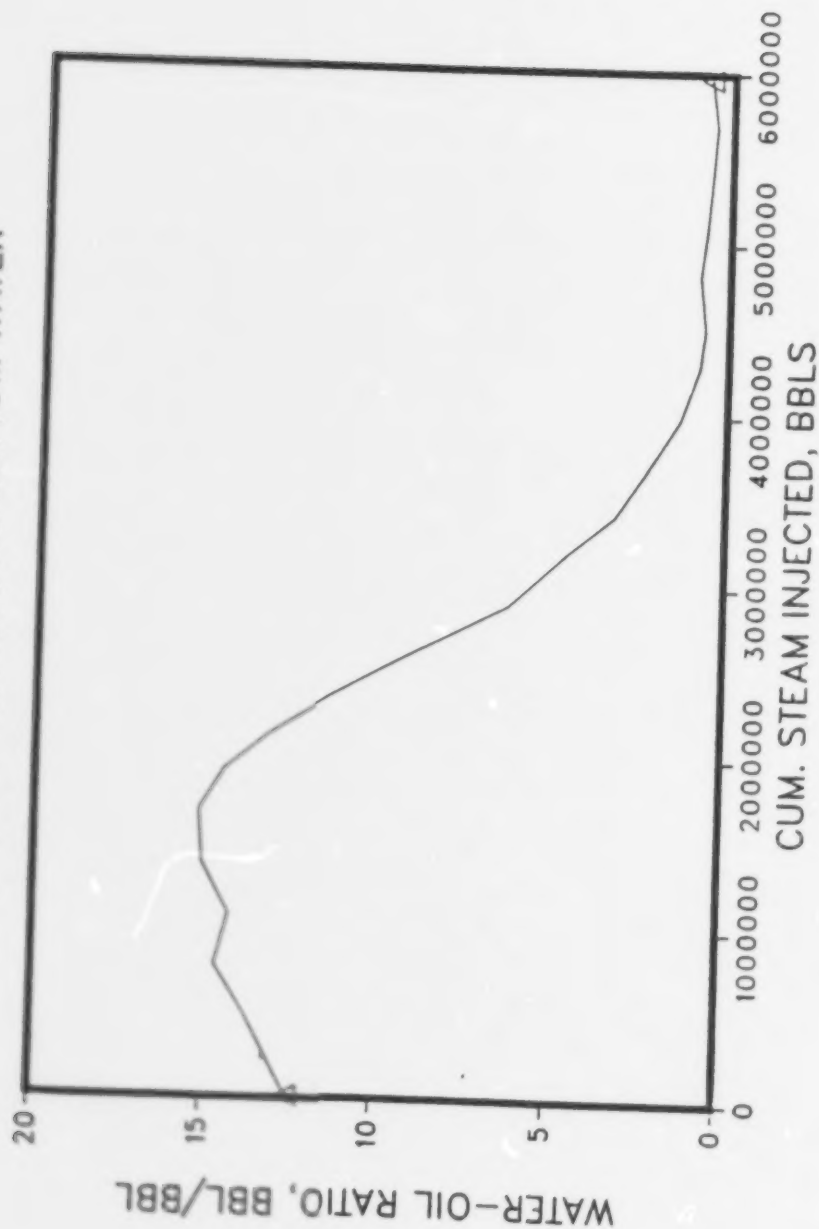


Figure 6.116 Water-Oil Ratio for Steam Injection with a Variable Steam Quality in the Wellbore, with Steam Offtake at Two Points

ABRWB1 SPEC RUN FOR WELLBRE ABERFELDY
VARIABLE QLTY, P; NO BOTTOM WATER

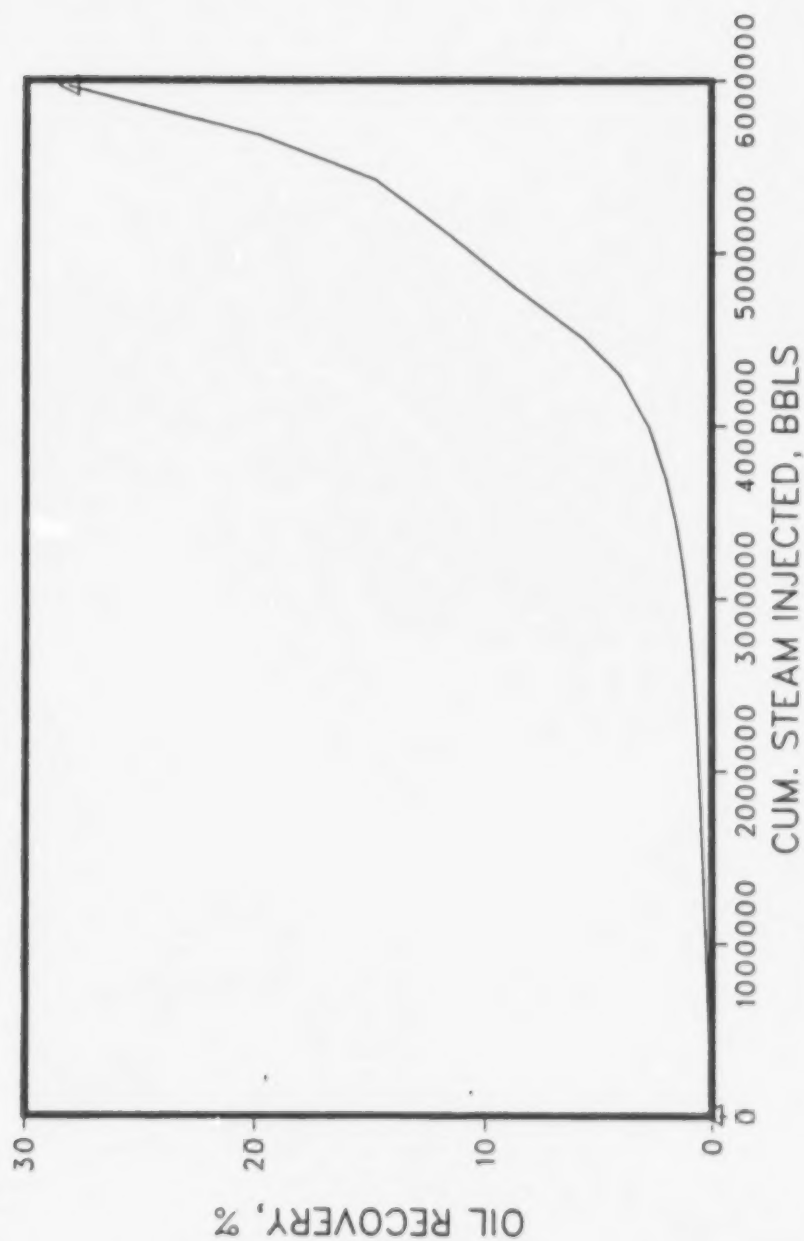


Figure 6.117 Oil-Steam Ratio for Steam Injection with a Variable Steam Quality in the Wellbore, with Steam Offtake at Two Points

ABRWB1 SPEC RUN FOR WELLBRE ABERFELDY
 VARIABLE QLTY, P; NO BOTTOM WATER

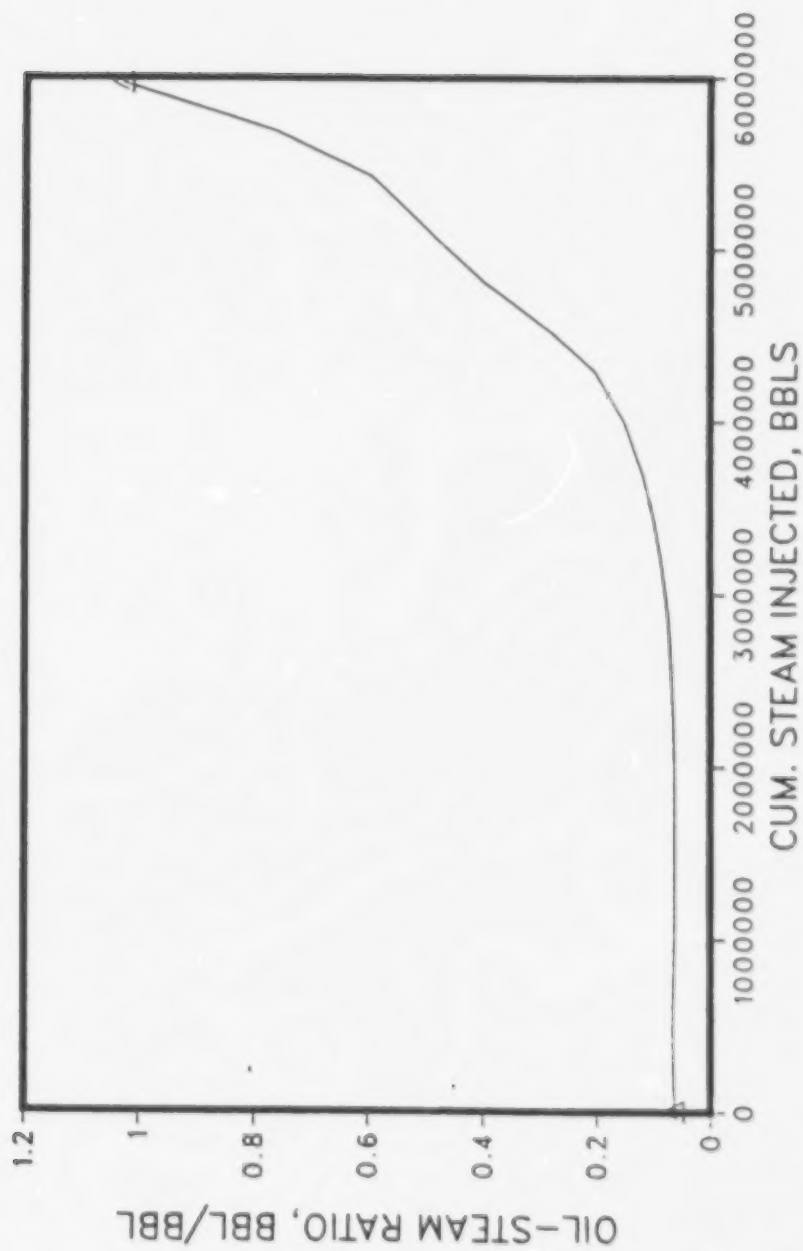


Figure 6.118 Oil Recovery for Steam Injection with a Variable Steam Quality in the Wellbore, with Steam Offtake at Two Points

Table: 6.13
ABRWB0: SPEC RUN WELLBORE ABERFELDY; CONST QLTY, P
NO BOTTOM WATER

Legend:

T : Time, Days
OPR : Oil Production Rate, Bbls/Day
WPR : Water Production Rate, Bbls/Day
WOR : Cumulative Water-Oil Ratio, Bbl/Bbl
CSI : Cumulative Steam Injected, 10^5 Bbls
ORec : Oil Recovery, %
OSR : Cumulative Oil-Steam Ratio, Bbl/Bbl

T	OPR	WPR	WOR	CSI	ORec	OSR
13	19.1	238	12.44	0.079	0.002	0.0319
668	20.9	365	17.46	4.012	0.128	0.0348
1158	24.0	501	20.86	6.949	0.226	0.0355
1473	27.2	571	20.98	8.840	0.301	0.0372
1950	31.4	607	19.28	11.703	0.430	0.0401
2553	40.0	590	14.73	15.322	0.628	0.0447
3239	62.1	616	9.92	19.437	0.947	0.0532
3725	86.2	560	6.49	22.355	1.282	0.0627
4011	111.3	535	4.81	24.069	1.544	0.0701
4603	180.6	576	3.19	27.621	2.383	0.0942
5061	217.1	557	2.57	30.366	3.229	0.1162
5561	273.1	531	1.94	33.366	4.367	0.1430
6061	380.3	542	1.42	36.366	5.879	0.1766
6558	761.1	617	0.81	39.351	8.412	0.2335
7069	885.9	801	0.90	42.413	12.339	0.3178
7495	716.7	680	0.95	44.970	15.417	0.3745
7988	1010.3	920	0.91	47.931	18.981	0.4326
8544	1588.7	1875	1.18	51.265	27.202	0.5796
9014	1746.5	1425	0.82	54.085	33.035	0.6672
9529	1210.7	2709	2.24	57.179	41.283	0.7887
9967	663.4	1948	2.94	59.807	44.891	0.8200

Table: 6.14
ABRWB1: SPEC RUN FOR WELLBORE ABERFELDY; VARIABLE QLTY, P
NO BOTTOM WATER

Legend:

T : Time, Days
OPR : Oil Production Rate, Bbls/Day
WPR : Water Production Rate, Bbls/Day
WOR : Cumulative Water-Oil Ratio, Bbl/Bbl
CSI : Cumulative Steam Injected, 10^5 Bbls
ORec : Oil Recovery, %
OSR : Cumulative Oil-Steam Ratio, Bbl/Bbl

T	OPR	WPR	WOR	CSI	ORec	OSR
13	19.1	238	12.44	0.080	0.002	0.0638
779	19.2	263	13.68	4.676	0.143	0.0670
1279	17.9	262	14.63	7.676	0.227	0.0647
1779	18.0	258	14.27	10.676	0.310	0.0634
2279	18.4	278	15.07	13.676	0.393	0.0628
2779	19.2	292	15.18	16.676	0.479	0.0628
3181	20.5	297	14.46	19.088	0.553	0.0633
3512	22.2	295	13.27	21.076	0.618	0.0641
3896	25.3	290	11.45	23.378	0.702	0.0656
4317	31.1	285	9.14	25.906	0.812	0.0685
4809	46.3	291	6.28	28.854	0.988	0.0748
5309	65.1	302	4.64	31.854	1.247	0.0856
5697	91.5	294	3.21	34.184	1.536	0.0981
6147	127.0	293	2.31	36.882	1.996	0.1182
6647	192.9	262	1.36	39.882	2.742	0.1502
7147	354.8	296	0.83	42.882	4.004	0.2040
7505	574.5	402	0.70	45.028	5.659	0.2746
8026	653.5	570	0.87	48.160	8.859	0.4019
8474	605.3	423	0.70	50.846	11.385	0.4892
9038	721.1	407	0.56	54.232	14.752	0.5943
9473	2026.2	966	0.48	56.840	19.781	0.7604
9948	1804.4	1199	0.66	59.688	28.138	1.0299

Chapter VII

EXPERIMENTAL APPARATUS AND PROCEDURE

The apparatus used in this study was designed based on the low pressure scaling criteria. One of the first steps in designing a physical model to simulate a field system is to determine the characteristics to be used to describe the prototype reservoir. The values listed in Table 7.1 were chosen to represent the Aberfeldy prototype.

The Physical Model

The model was designed to represent one-quarter of an eight hectare (twenty acre) five-spot pattern, and as such, had one injection well and one production well at diagonally opposite corners. The size of the model is limited in that it must be of a size suitable for a laboratory, and that the experimental run time must not be prohibitive. With these constraints, the model was chosen to be 81.3 cm (32 in.) square and 6.4 cm (2.5 in.) thick. This produces a geometric scaling factor of 173.2.

The scaled model operating parameters were calculated in the manner described in the previous report. The operating parameters for the Aberfeldy scaled model are summarized in Table 7.2. Note that the time scale is 12.18 minutes in the model for each year in the prototype, thus a great deal of data is produced in a very short time during an experimental run.

A schematic diagram of the apparatus used in this research is presented as Figure 7.1. The main components of the apparatus are the physical model, the steam injection system, the model cart and cold storage unit, the fluid collection system, and the data acquisition system. A brief description of each of these main components of the apparatus is given below.

Fiberglass was chosen as the model material because it has a relatively low heat transfer coefficient, it is inexpensive to fabricate, it is relatively easy to machine, and it can be constructed to be capable of withstanding the severe loading induced on the model as a result of the vacuum scaling requirements. The high permeability required by the scaling

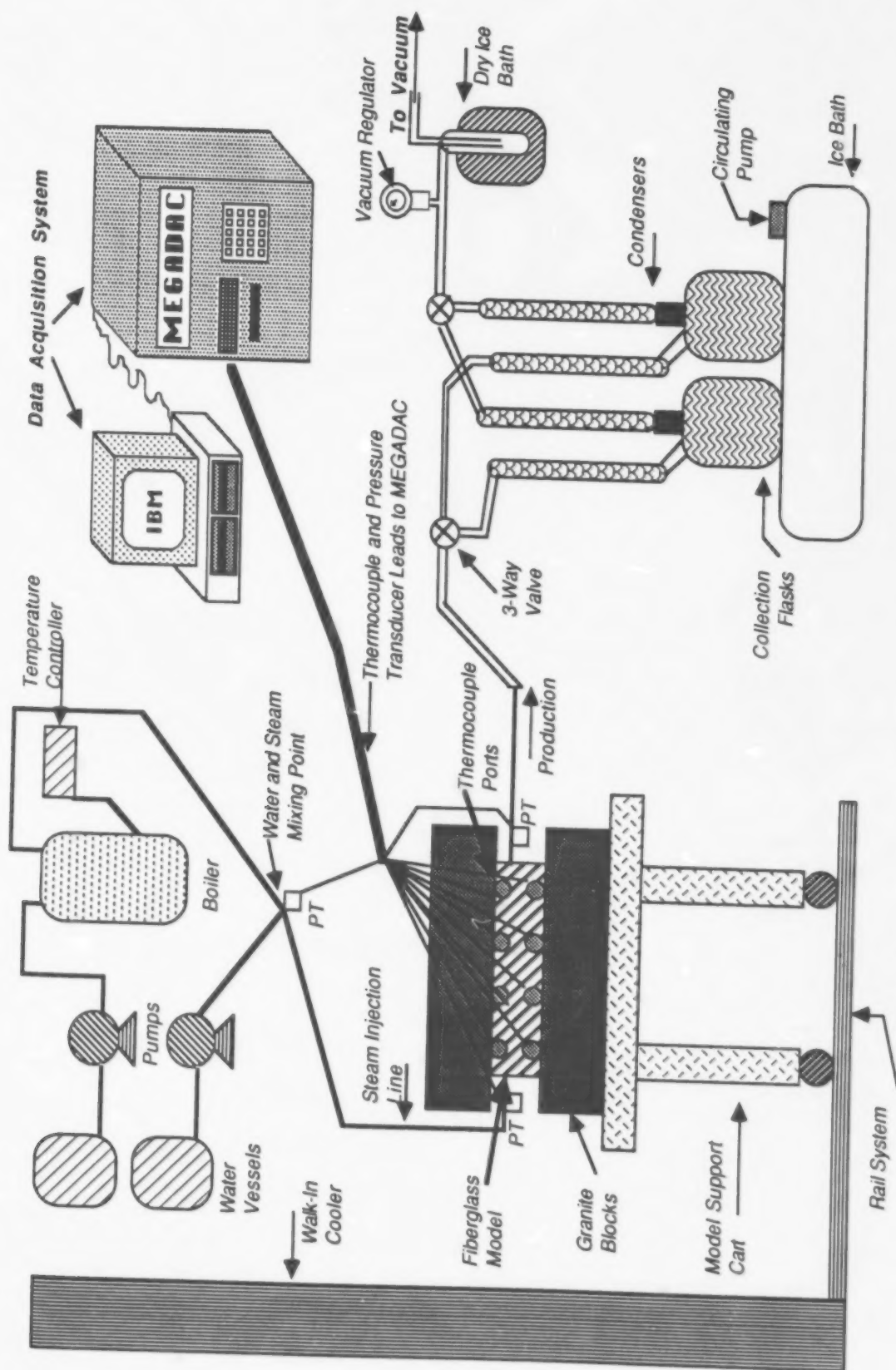


Figure 7.1 : Schematic Diagram of Apparatus

Table 7.1 : Prototype Reservoir Data

Net Pay Thickness:	11 m (36 ft.)
Porosity:	0.31
Permeability:	2000 md
Thermal Conductivity:	0.002077 kW/(m.K) (1.2 Btu/hr.ft. ⁰ F)
Heat Capacity:	2.2217 kJ/(kg.K)
Initial Saturation:	$S_o = 0.75$, $S_g = 0.02$, $S_w = 0.23$
Steamflood Residual Oil Saturation:	$S_{or} = 0.15$
Oil Viscosity:	1275 mPa.s at 23.9 °C (75 °F)
Water Viscosity	0.891 mPa.s at 25.8 °C (78.4 °F)
Initial Reservoir Temperature:	23.3 °C (74 °F)
Steam Injection Pressure:	1.900 MPa (275.5 psi)
Steam Injection Rate:	100-150 m ³ /day (630-945 bbl./day)
Steam Quality:	0.70 (Actually is 0.80 but a lower value was chosen to allow for wellbore heat losses.)

Table 7.2 : Summary of the Scaling Calculations for the Aberfeldy Model

Length Scale:	$\gamma(L) = L_p/L_m = 173.2$
Pressure Relation:	$P_m = 0.004683 + 0.006415 P_p$ (MPa)
Temperature Relation:	$T_m = 0.286 T_p - 3.657$ (°C)
Time Scale:	$t_m/t_p = 12.18$ minutes/year
Permeability:	prototype = 2 darcies model = 4216.5 darcies
Injection and Production Rate Scales:	$w_m/w_p = 9.0728$ (cm ³ /min.)/(m ³ /day)
Initial Model Temperature:	3 °C
Model Pressure:	Production end: 7 kPa (1 psia) Injection end: Near atmospheric pressure

criteria was achieved by using glass beads with a diameter of approximately three millimeters (6-8 mesh). The cap and base rocks of the model consisted of granite blocks, which closely modeled the heat transfer between the cap and base rocks of the actual reservoir.

Model Wells

Important components of the model were the injection and production wells. These were constructed out of aluminum rod and set into diagonally opposite corners of the molded fiberglass model. The wells were designed according to the slot well method, used previously, which resulted in a model well slit of 0.1088 inches representing a prototype well with a six inch diameter. The wells were designed to allow a gate device to be inserted into them, which enabled the experimenter to selectively choose the injection and production intervals.

Steam Injection System

A new steam generator was installed in this phase of the contract to allow for more control over the steam temperature. The new boiler system consisted of an insulated oil bath containing eight fire rods which heated the bath quickly and uniformly at a rate determined by an electronic temperature controller. Water passed through an eighty foot length of coiled, stainless steel tubing contained in this hot oil bath. This boiler system was set up to produce a superheated steam at 120°C which was mixed with a stream of room temperature water to produce a steam quality representing a prototype steam quality of 70%. Controlled volume pumps were used to pump de-aired, distilled water to the steam generator and to the water-steam mixing point.

A unique design was employed in the construction of many components of the experimental apparatus and the model support cart is a good example of this. A shaft was welded into the support area for the model and this shaft was connected by a rack and pinion to a gear box. This gear box imparted a tremendous mechanical advantage so that the entire 2000 kg model apparatus could be rotated with ease to improve the efficiency of

the saturation process and to allow the simulation of dipping reservoirs for future experiments. A walk-in cooler was used to cool the model to the initial temperature of 3°C as required by the scaling groups. The model cart was set on castors which rolled on tracks to facilitate the movement of the model in and out of the cold storage room.

Collection System

Operating the experiments under vacuum conditions introduced special considerations into the design of a collection system. The pore volume of the model was too large to allow the use of a single container to collect the produced fluids and very little information could be obtained from a single sample. Therefore, the system used two 2000 ml flasks to collect the produced fluids, which were arranged so that they could be isolated from the vacuum and emptied individually. Because the vacuum was applied through the collection system, it was expected that some vaporization of the produced fluids would occur. For this reason, the collection system included a series of condensers and cold traps to collect and retain all of the produced fluids.

Thirty-one thermocouples were placed in two layers within the model at strategic points for the purpose of recording the heat fronts through the model. Figure 7.2 schematically illustrates the thermocouple positions within the model. Other thermocouples and several pressure transducers were also placed throughout the system. A MEGADAC 2000 data acquisition system, from OPTIM Electronics Corporation was used to collect data during the experimental runs. The MEGADAC was controlled by an IBM PC and was programmed to scan each thermocouple and pressure transducer once every thirty seconds.

Model Fluids

Oil for the Aberfeldy Model

Faxam-100 was the oil chosen for the Aberfeldy model. The Faxam-100 was supplied by Imperial Oil Limited and the temperature-viscosity profile for this oil provided a reasonable match to the desired temperature-viscosity profile of the ideal model oil. Therefore the Faxam-100 was chosen as the actual model oil. A comparison of the

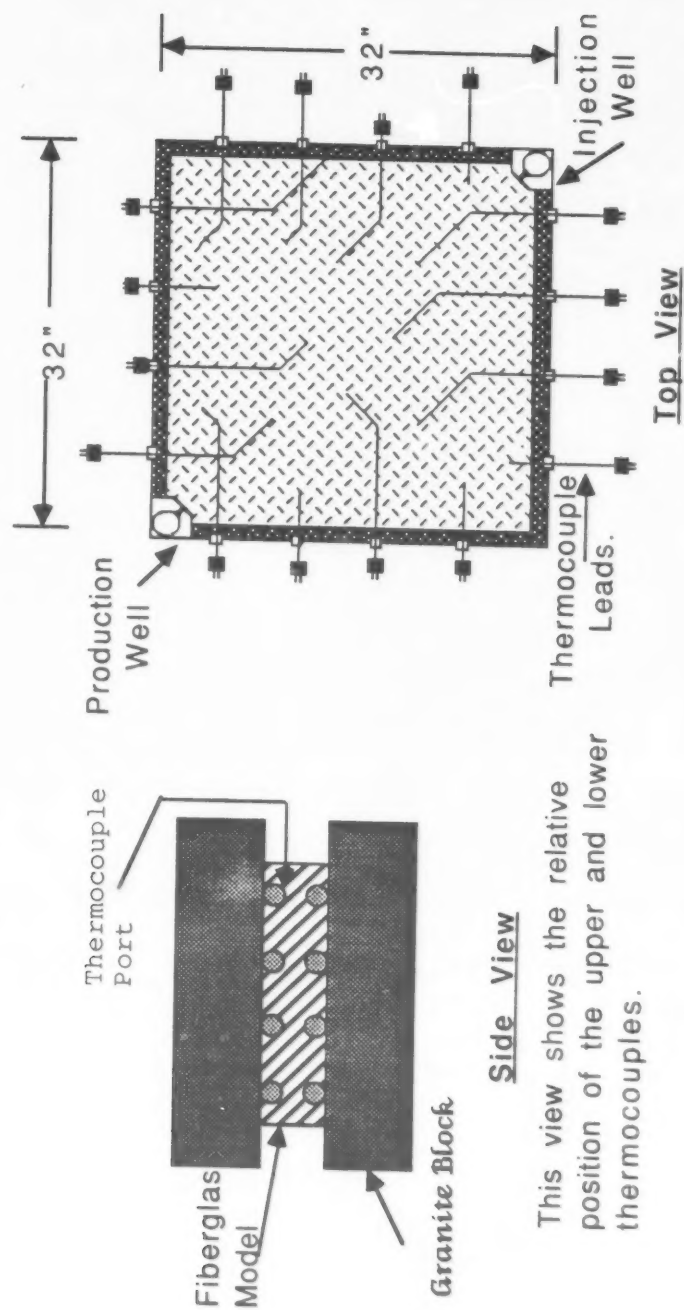


Figure 7.2 : Schematic Diagram of Model Illustrating Thermocouple Positions.

temperature-viscosity profiles for the ideal model oil and the actual model oil (Faxam-100) is illustrated in Figure 7.3.

Selection of the Solvent

An extensive viscosity analysis was performed in order to decide upon an appropriate solvent that could be incorporated into the steamflood experiments of the vacuum model.

The viscosity study involved analyzing Heavy Virgin Naphtha, Light Virgin Naphtha and Synthetic Crude. Each solvent was combined with the model oil (Faxam-100) and the viscosity behaviour of these solvent mixtures was measured at different temperatures and mixture concentrations.

The upper temperature range of the model during a steamflood run will be approximately 60^o to 80^oC which means that the Heavy Virgin Naphtha will be partially vaporized in this range. Partial vaporization of the solvent is favourable since this further enhances the mobilization of oil by the diffusion of solvent vapour into the oil ahead of the solvent bank. The Heavy Virgin Naphtha and the Light Virgin Naphtha had very similar viscosities but the Light Virgin Naphtha was not chosen because it had a relatively low initial boiling point (30.5^oC) compared to the other two solvents and would almost entirely be vaporized at the model's steamflood temperatures. The Heavy Virgin Naphtha was chosen as the solvent since it has a higher initial boiling point (61.0^oC) than the Light Virgin Naphtha and lower viscosity values than the Synthetic Crude. By overlaying the two viscosity profiles provided for the Heavy Virgin Naphtha (Figure 7.4) and the Synthetic Crude (Figure 7.5) it can be seen that the Heavy Virgin Naphtha has a greater viscosity reduction capability which is very desirable for this type of recovery process.

Some pertinent properties of the Heavy Virgin Naphtha are listed below.

$$\rho_{\text{HVN}} = 0.7320 \text{ g/cm}^3$$

$$\text{API Gravity} = 61.7418^{\circ} \text{ API}$$

$$\text{Initial Boiling Point} = 61.0^{\circ}\text{C}$$

$$\text{Final Boiling Point} = 131.5^{\circ}\text{C}$$

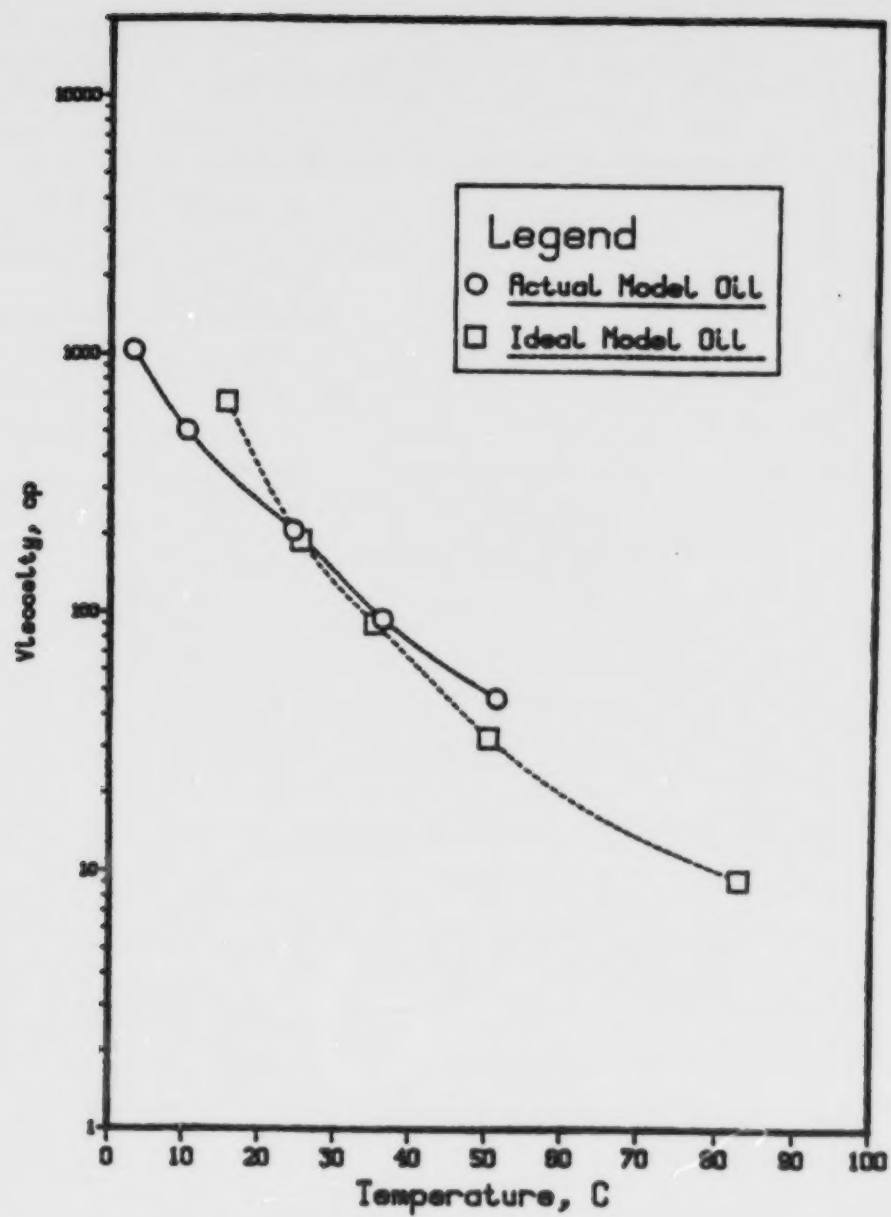


Figure 7.3 Temperature-Viscosity Profile for Ideal and Actual Model Oil

Mixture Viscosity Vs. Heavy Virgin Naphtha Concentration

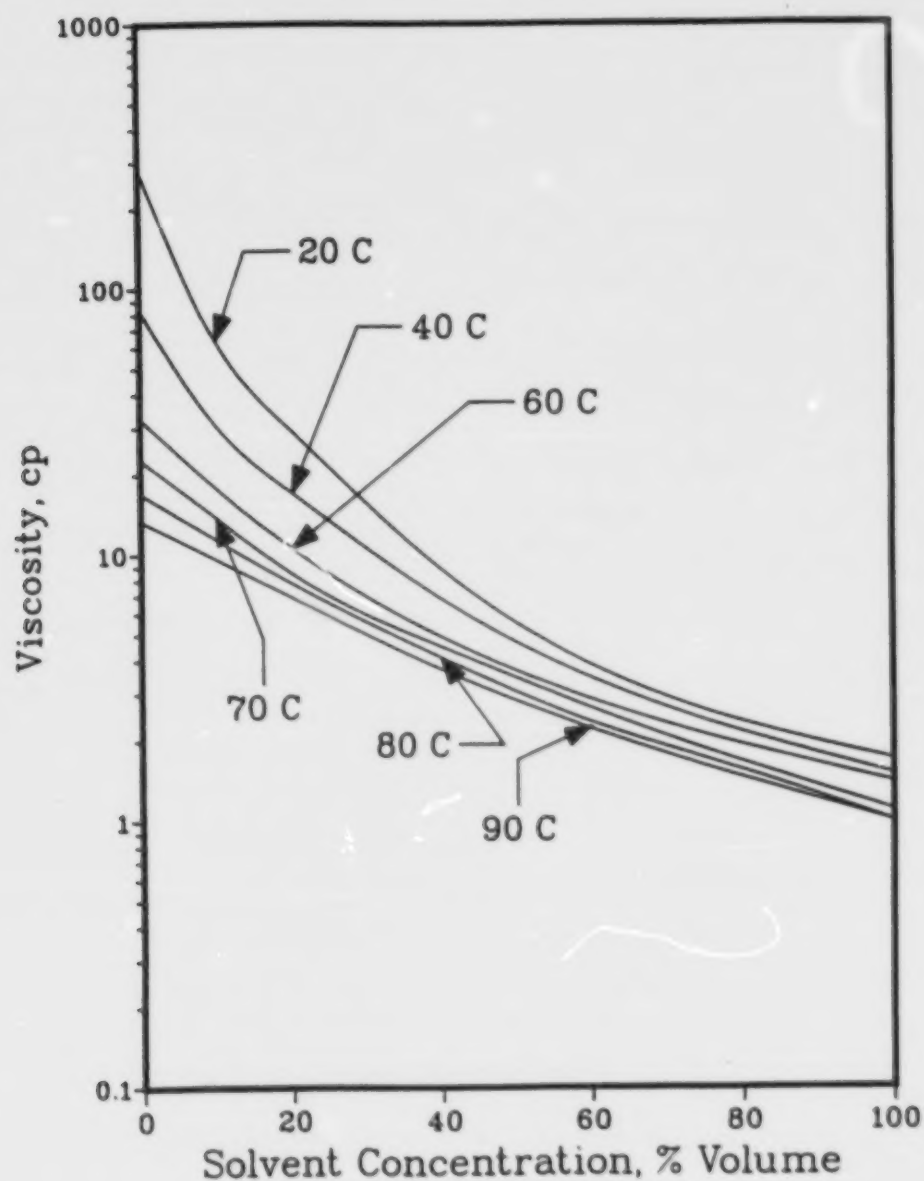


Figure 7.4

Mixture Viscosity Vs. Synthetic Crude Concentration

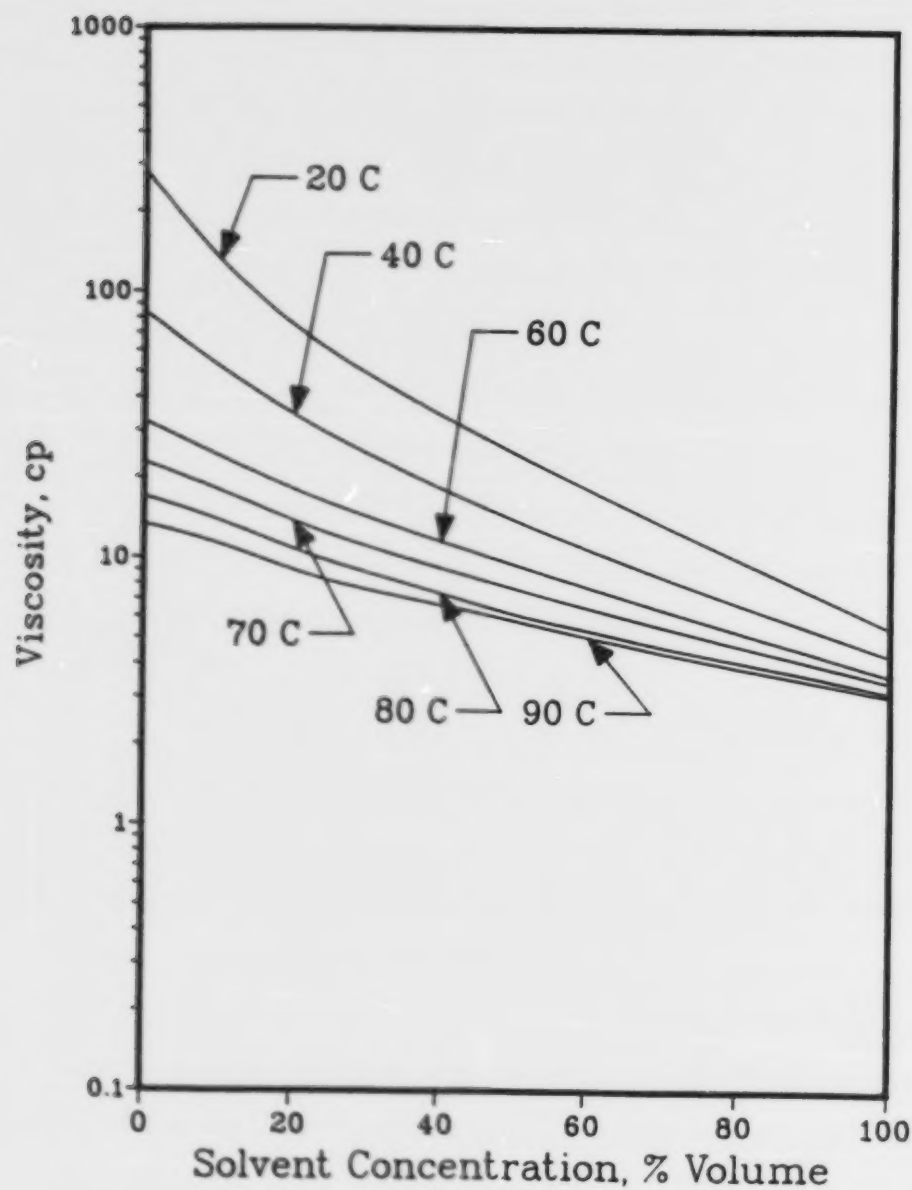


Figure 7.5

The Heavy Virgin Naphtha was supplied by ESSO Petroleum Canada, Strathcona Refinery.

Model Packing and Saturation

Due to the size and shape of the model, packing methods such as tamping or vibrating are not practical. Therefore a particle distributor was constructed and used to pack the glass beads within the model. This method of packing was first proposed by Currie and Gregory and later modified by Wygal.

After packing the model with glass beads, a Teflon sheet was placed above the model and a thin layer of silicone was applied between the Teflon sheet and the fiberglass model to provide a vacuum tight seal. A rubber sheet was placed above the Teflon sheet to ensure that complete contact was made between the porous media and the upper granite block, which was then set in place above the model. The entire model was then tilted to facilitate the saturation process.

Six large saturation ports were incorporated into the model (three on each of two opposite sides) to improve the efficiency of the saturation process. With the apparatus in a tilted position, the fluids entered the model from the downdip end and thus the fluid flow into the model proceeded with a gravity stabilized front. To begin the saturation process, a vacuum was applied at the updip end and de-aired, distilled water was pulled into the model through the saturation ports at the downdip end. This continued until the model was completely saturated with water. The amount of water taken up during this saturation process was carefully measured and the model porosity was calculated using this water volume. Next, oil was drawn into the model by a method similar to that described for the water, which brought the model to irreducible water saturation. After saturation was complete, the apparatus was rolled into the cooler where it was left until it reached the low initial temperature required by the scaling groups.

For bottom water experiments, the saturation procedure was necessarily different. The water layer was established in the model by packing the model with just enough beads

to cover the volume of water required to obtain the desired bottom water thickness. The beads and water were then frozen in place. With the bottom water layer frozen in place, the model was saturated in a manner similar to that described previously for the homogeneous packs. An innovative approach was used to determine the volume of bottom water that had thawed and been displaced during the saturation process. The bottom water layer was made up of a 5% solution of NaCl, and by measuring the refractive index of this solution, distilled water, and the sample displaced during saturation, the volume of bottom water remaining in the model after saturation could be determined. By the same method, the volume of bottom water produced during the steamflood experiment could also be determined.

Conducting the Experiments

With all of the necessary preparations complete, the model was rolled out of the cooler and all thermocouple and pressure transducer leads were connected, the injection and production lines were attached, and the data acquisition unit was reset for a new experiment. During the experiment, the production flasks were emptied into a series of 2000 ml graduated cylinders where instantaneous oil and water recovery could be observed as a function of each two litres of total production. Steam injection was continued until one and one half to two pore volumes had been injected.

Data Analysis

Following the run, a table of instantaneous and cumulative production as functions of the number of pore volumes of steam injected was prepared. Several plots were generated for each run to analyze the data. These included the following:

- A plot of cumulative recovery vs. pore volumes of steam injected.
- A plot of instantaneous oil and water recovery as a function of pore volumes of steam injected.
- A plot of instantaneous oil-steam ratio as a function of the cumulative oil production.

- Temperature profiles at 0.25, 0.50, 0.75, 1.00, 1.25, and 1.50 pore volumes of steam injected.

In addition to these plots, plots were generated to compare the production response resulting from varying recovery schemes and experimental conditions.

Chapter VIII

EXPERIMENTAL RESULTS AND DISCUSSION

The scaled physical model described in this paper has been employed for steamfloods of various types. Table 8.1 lists the types of experiments which have been conducted along with information concerning the initial model conditions and the experimental results. It can be seen that the vacuum scaled model is capable of representing a large variety of situations and enables one to experiment with numerous steamflooding strategies.

Numerous experiments were conducted on a scaled model simulating the Aberfeldy reservoir of Saskatchewan. These included continuous steamfloods in homogeneous models, steamfloods in bottom water models, steamfloods following the injection of a small volume of an inert gas in homogeneous and bottom water models, steamfloods utilizing horizontal wells, and steamfloods performed in conjunction with solvent injection.

Continuous Steamflood Experiments In Homogeneous Models

Several continuous steamflood experiments were conducted in homogeneous models to establish a basis for evaluating the efficiency of other production process which would be tested. These experiments differed from continuous steamfloods conducted in Phase I of this project in that they incorporated a new and improved saturation technique. This new technique involved flowing approximately 0.5 extra pore volumes of the saturating fluid through the model during the saturation process to ensure that saturation was complete. This is thought to result in a more uniformly saturated model.

Runs 23, 26, and 27 were continuous steamfloods conducted on homogeneous models. Tables 8.2, 5, and 8.4 provide the experimental parameters and recovery response of Runs 23, 26, and 27, respectively. The final recovery observed for Run 23 was 39.9% ooip after 2.11 pore volumes had been produced. The final recovery observed for Run 26 was 31.8% ooip after 1.97 pore volumes had been produced while the final recovery

Table 8.1 : List of the Experiments

Run #	Model Type	Process	Special Features	Porosity (%)	Soi (%)	Swi (%)	Cum. Rec. (%OOIP)	Cum. PV Inj.
1	Homogeneous Model	Preliminary Experiment	Water saturated model.	-	0.00	100.00	NA	NA
2	Homogeneous Model	Preliminary Experiment	Water saturated model.	-	0.00	100.00	NA	NA
3	Homogeneous Model	Preliminary Experiment	Water saturated model.	-	0.00	100.00	NA	NA
4	Homogeneous Model	Continuous Steamflood	Water saturated model.	32.40	0.00	100.00	NA	NA
5	Homogeneous Model	Continuous Steamflood		33.80	86.74	13.26	6.59	0.4500
6	Homogeneous Model	Continuous Steamflood		33.30	84.49	15.51	21.89	2.3400
7	Homogeneous Model	Cold Waterflood		31.00	90.41	9.59	22.52	1.1730
7B	Homogeneous Model	Room Temperature Waterflood		31.00	-	-	26.47	1.6750
7C	Homogeneous Model	Continuous Steamflood		31.00	-	-	32.40	2.8670
8	Homogeneous Model	Unsuccessful Run	Heavy oil experiment (13000cp).	35.90	NA	NA	NA	NA
9	Homogeneous Model	Continuous Steamflood	Heavy oil experiment (13000cp).	32.90	87.68	12.32	1.65	1.0100
10	Homogeneous Model	Continuous Steamflood		30.20	92.00	8.00	31.38	2.1140
11	Homogeneous Model	Unsuccessful Run (Vacuum Leak)		30.80	85.28	14.72	NA	NA
12	Homogeneous Model	Continuous Steamflood	Light oil experiment (25.6cp).	33.50	89.22	10.78	32.95	1.4356
13	Homogeneous Model	Continuous Steamflood	Light oil experiment (25.6cp).	30.10	92.18	7.82	35.52	1.6524
14	Homogeneous Model	Unsuccessful Run (Vacuum Leak)	Light oil experiment (25.6cp).	33.10	90.22	9.78	NA	NA
15	Bottom Water Model	Continuous Steamflood		35.90	76.34 (avg.)	23.66 (avg.)	3.08	1.2100
16	Homogeneous Model	Unsuccessful Run (Vacuum Leak)		32.40	93.47	6.53	NA	NA
17	Homogeneous Model	Waterflood Following a Steam Slug		32.90	92.62	7.38	24.22	1.0310
18	Homogeneous Model	Waterflood Following a Steam Slug		33.00	92.00	8.00	30.85	1.4440
19	Homogeneous Model	Waterflood Following a Steam Slug		33.30	91.52	8.48	30.07	1.5600
20	Homogeneous Model	Unsuccessful Run (Prod. Well Plugging)		32.10	93.41	6.59	NA	NA
21	Homogeneous Model	Unsuccessful Run (Prod. Well Plugging)		32.50	94.36	5.64	NA	NA
22	Homogeneous Model	Hot Waterflood		34.10	89.45	10.55	25.91	1.3540
23	Homogeneous Model	Continuous Steamflood	Improved saturation technique.	33.09	89.53	10.47	39.94	2.1072
24	Homogeneous Model	Gas Injection Prior to Steamflood.		33.52	94.03	5.97	29.57	1.8548
25	Homogeneous Model	Gas Injection Prior to Steamflood.	Injection into upper portion of mode	33.34	94.68	5.32	26.58	1.8533
26	Homogeneous Model	Continuous Steamflood	Injection into lower portion of mode	33.46	94.77	5.23	31.76	1.9719
27	Homogeneous Model	Continuous Steamflood		33.29	95.10	4.90	32.18	2.2513
28	Homogeneous Model	Gas Injection Prior to Steamflood.	Run spoiled by damaged boiler.	32.65	92.53	7.47	NA	NA
29	Homogeneous Model	Gas Injection Prior to Steamflood.		33.50	89.41	10.59	27.34	1.9200
30	Bottom Water Model	Gas Injection Prior to Steamflood.	Injection into upper portion of mode	36.09	75.96 (avg.)	24.04 (avg.)	26.18	2.2296
31	Bottom Water Model	Continuous Steamflood	Saline B.W. (6000cc), Inj-t, Prod-t	36.66	89.77 (avg.)	10.23 (avg.)	27.67	1.8406
32	Bottom Water Model	Continuous Steamflood	Saline B.W. (8000cc), Inj-t, Prod-t	34.01	95.36 (avg.)	4.64 (avg.)	22.75	1.8712
33	Bottom Water Model	Continuous Steamflood	Inj. into lower portion of mode.	37.33	86.70 (avg.)	13.30 (avg.)	22.91	1.7582
34	Homogeneous Model	Horizontal Well	Horizontal Inj. and Prod. well.	32.76	93.64	6.36	25.96	1.9800
35	Homogeneous Model	Horizontal Well	Prod. well horizontal, Inj. vert.	33.47	91.36	8.64	29.00	1.8055
36	Homogeneous Model	Horizontal Well	Inj. and Prod. well horizontal.	34.00	90.44	9.56	24.78	1.7840
37	Bottom Water Model	Gas Injection Prior to Steamflood.	Inj. into top, prod. over entire int.	36.07	85.25 (avg.)	14.75 (avg.)	20.94	1.9805
38	Bottom Water Model	Gas Injection Prior to Steamflood.	Inj. over entire int., prod. from top.	36.91	84.91 (avg.)	15.09 (avg.)	20.66	1.8262
39	Bottom Water Model	Continuous Steamflood	Inj. over entire int., prod. from top.	37.09	86.01 (avg.)	13.99 (avg.)	16.79	1.7827
40	Homogeneous Model	Continuous Solventflood	Inj. into top, prod. over entire int.	33.70	92.47	7.53	26.75	2.2479

Table 8.2 : Experimental Data For Run 23
Model Simulating the Aberfeldy Reservoir--Continuous Steamflood In Homogeneous Model

Pore Volume of Bead Pack: 13900.0 cc
 Porosity of Bead Pack: 33.09 %
 Hydrocarbon Pore Volume: 12445.0 cc
 Initial Oil Saturation: 89.53 %
 Irreducible Water Saturation: 10.47 %
 Initial Model Temperature: 3.0 C
 Water Feed Flow Rate: 199.3 cc
 Steam Feed Flow Rate: 30.1 cc
 Total Steam Injection Rate: 229.4 cc

Sample	Sample Volume (cc)	Water Volume (cc)	Total Cumulative Production (cc)	(PV)	Cumulative Oil Produced (cc)	(%oioip)	Water in Sample(%)	Oil in Sample (%)	Inst. OSR	Cum. OSR
1	1970.0	400.0	1970.0	0.1417	1570.0	12.62%	20.30%	79.70%	0.7970	0.7970
2	1840.0	800.0	3810.0	0.2741	2610.0	20.97%	43.48%	56.52%	0.5652	0.6850
3	2000.0	1480.0	5810.0	0.4180	3130.0	25.15%	74.00%	26.00%	0.2600	0.5387
4	2150.0	1770.0	7960.0	0.5727	3510.0	28.20%	82.33%	17.67%	0.1767	0.4410
5	1940.0	1700.0	9900.0	0.7122	3750.0	30.13%	87.63%	12.37%	0.1237	0.3788
6	1880.0	1680.0	11780.0	0.8475	3950.0	31.74%	89.36%	10.64%	0.1064	0.3353
7	1970.0	1820.0	13750.0	0.9892	4100.0	32.94%	92.39%	7.61%	0.0761	0.2982
8	1840.0	1700.0	15590.0	1.1216	4240.0	34.07%	92.39%	7.61%	0.0761	0.2720
9	1910.0	1780.0	17500.0	1.2590	4370.0	35.11%	93.19%	6.81%	0.0681	0.2497
10	1840.0	1720.0	19340.0	1.3914	4490.0	36.08%	93.48%	6.52%	0.0652	0.2322
11	2060.0	1960.0	21400.0	1.5396	4590.0	36.88%	95.15%	4.85%	0.0485	0.2145
12	1860.0	1770.0	23260.0	1.6734	4680.0	37.61%	95.16%	4.84%	0.0484	0.2012
13	1960.0	1860.0	25220.0	1.8144	4780.0	38.41%	94.90%	5.10%	0.0510	0.1895
14	1870.0	1780.0	27090.0	1.9489	4870.0	39.13%	95.19%	4.81%	0.0481	0.1798
15	2200.0	2100.0	29290.0	2.1072	4970.0	39.94%	95.45%	4.55%	0.0455	0.1697

Table 8.3 : Experimental Data For Run 26
Model Simulating the Aberfeldy Reservoir--Continuous Steamflood In Homogeneous Model
Injection into Lower Portion of Model

Pore Volume of Bead Pack: 14055.0 cc
 Porosity of Bead Pack: 33.46 %
 Hydrocarbon Pore Volume: 13320.0 cc
 Initial Oil Saturation: 94.77 %
 Irreducible Water Saturation: 5.23 %
 Initial Model Temperature: 3.0 C
 Water Feed Flow Rate: 199.3 cc
 Steam Feed Flow Rate: 30.1 cc
 Total Steam Injection Rate: 229.4 cc

Sample	Sample Volume (cc)	Water Volume (cc)	Total Cumulative Production (cc)	(PV)	Cumulative Oil Produced (cc)	(%oioip)	Water in Sample(%)	Oil in Sample (%)	Inst. OSR	Cum. OSR
1	1990.0	290.0	1990.0	0.1416	1700.0	12.76%	14.57%	85.43%	0.8543	0.8543
2	1965.0	1405.0	3955.0	0.2814	2260.0	16.97%	71.50%	28.50%	0.2850	0.5714
3	1940.0	1595.0	5895.0	0.4194	2605.0	19.56%	82.22%	17.78%	0.1778	0.4419
4	1885.0	1655.0	7780.0	0.5535	2835.0	21.28%	87.80%	12.20%	0.1220	0.3644
5	2070.0	1860.0	9850.0	0.7008	3045.0	22.86%	89.86%	10.14%	0.1014	0.3091
6	1960.0	1815.0	11810.0	0.8403	3190.0	23.95%	92.60%	7.40%	0.0740	0.2701
7	2020.0	1865.0	13830.0	0.9840	3345.0	25.11%	92.33%	7.67%	0.0767	0.2419
8	1900.0	1750.0	15730.0	1.1192	3495.0	26.24%	92.11%	7.89%	0.0789	0.2222
9	2060.0	1935.0	17790.0	1.2657	3620.0	27.18%	93.93%	6.07%	0.0607	0.2035
10	1880.0	1760.0	19670.0	1.3995	3740.0	28.08%	93.62%	6.38%	0.0638	0.1901
11	2030.0	1900.0	21700.0	1.5439	3870.0	29.05%	93.60%	6.40%	0.0640	0.1783
12	1925.0	1825.0	23625.0	1.6809	3970.0	29.80%	94.81%	5.19%	0.0519	0.1680
13	2090.0	1955.0	25715.0	1.8296	4105.0	30.82%	93.54%	6.46%	0.0646	0.1596
14	2000.0	1875.0	27715.0	1.9719	4230.0	31.76%	93.75%	6.25%	0.0625	0.1526

Table 8.4 : Experimental Data For Run 27
Model Simulating the Aberfeldy Reservoir--Continuous Steamflood In Homogeneous Model

Pore Volume of Bead Pack: 13985.0 cc
 Porosity of Bead Pack: 33.29 %
 Hydrocarbon Pore Volume: 13300.0 cc
 Initial Oil Saturation: 95.10 %
 Irreducible Water Saturation: 4.90 %
 Initial Model Temperature: 3.0 C
 Water Feed Flow Rate: 199.6 cc
 Steam Feed Flow Rate: 30.1 cc
 Total Steam Injection Rate: 229.7 cc

Sample	Sample Volume (cc)	Water Volume (cc)	Total Cumulative Production (cc)	Total Cumulative Production (PV)	Cumulative Oil Produced (cc)	Cumulative Oil Produced (%oip)	Water in Sample(%)	Oil in Sample (%)	Inst. OSR	Cum. OSR
1	1975.0	355.0	1975.0	0.1412	1620.0	12.18%	17.97%	82.03%	0.8203	0.8203
2	2050.0	1655.0	4025.0	0.2878	2015.0	15.15%	80.73%	19.27%	0.1927	0.5006
3	1970.0	1640.0	5995.0	0.4287	2345.0	17.63%	83.25%	16.75%	0.1675	0.3912
4	1955.0	1680.0	7950.0	0.5685	2620.0	19.70%	85.93%	14.07%	0.1407	0.3296
5	1890.0	1670.0	9840.0	0.7036	2840.0	21.35%	88.36%	11.64%	0.1164	0.2886
6	2000.0	1805.0	11840.0	0.8466	3035.0	22.82%	90.25%	9.75%	0.0975	0.2563
7	1915.0	1750.0	13755.0	0.9836	3200.0	24.06%	91.38%	8.62%	0.0862	0.2326
8	1980.0	1800.0	15735.0	1.1251	3380.0	25.41%	90.91%	9.09%	0.0909	0.2148
9	1975.0	1750.0	17710.0	1.2664	3605.0	27.11%	88.61%	11.39%	0.1139	0.2036
10	2070.0	1960.0	19780.0	1.4144	3715.0	27.93%	94.69%	5.31%	0.0531	0.1878
11	1910.0	1805.0	21690.0	1.5509	3820.0	28.72%	94.50%	5.50%	0.0550	0.1761
12	1960.0	1865.0	23650.0	1.6911	3915.0	29.44%	95.15%	4.85%	0.0485	0.1655
13	1875.0	1780.0	25525.0	1.8252	4010.0	30.15%	94.93%	5.07%	0.0507	0.1571
	2070.0	1970.0	27595.0	1.9732	4110.0	30.90%	95.17%	4.83%	0.0483	0.1489
	1950.0	1870.0	29545.0	2.1126	4190.0	31.50%	95.90%	4.10%	0.0410	0.1418
14	1940.0	1850.0	31485.0	2.2513	4280.0	32.18%	95.36%	4.64%	0.0464	0.1359

observed for Run 27 was 32.2% ooip after 2.25 pore volumes had been produced. The results of experiments 26 and 27 are quite similar, but the recovery response of Run 23 was somewhat higher.

A curve fit program was developed to interpolate the recovery for each of these experiments in order to establish an average oil recovery response for the continuous steamflooding process. Table 8.5 lists the average cumulative production of the continuous steamflooding process as a function of pore volumes of steam injected, along with the interpolated recovery values for each of the three experiments. It can be seen that after two pore volumes of steam have been injected into the model, the average recovery is 34.1% OOIP.

Table 8.5. Cumulative Recovery vs. Pore Volumes of Steam Injected--
Continuous Steamflood in Homogeneous Model

PV Injected	Cumulative Production			
	Run 23	Run 26	Run 27	Average
0.25	19.8790	16.1900	14.4210	16.8300
0.50	26.8760	20.6420	18.7350	22.0843
0.75	30.6090	23.2740	21.8530	25.2453
1.00	33.0300	25.2480	24.2010	27.4930
1.25	35.0420	27.0830	26.9500	29.6917
1.50	36.6800	28.7760	28.4150	31.2903
1.75	38.0470	30.2510	29.7460	32.6813
2.00	39.3400	31.9160	31.0200	34.0920

Continuous Steamfloods in Bottom Water Models

Runs 31, 32, 33, and 39 were continuous steamfloods conducted in bottom water models. Tables 8.6, 8.7, 8.8, and 8.9 present the experimental parameters and results for runs 31, 32, 33, and 39, respectively. From these tables it can be seen that the bottom water thickness varied from 12.48% (Run 39) to 2.3% (Run 32) of the total model thickness. As discussed previously, the thickness of the bottom water layer is determined by using refractive index measurements to determine how much of the water which was originally frozen in the model had thawed and produced during saturation of the upper part

Table 8.6 : Experimental Data For Run 31
Model Simulating the Aberfeldy Reservoir--Continuous Steamflood In Bottom Water Model
Injection and Production From Upper Portion of Model

Pore Volume of Bead Pack: 15400.0 cc
Porosity of Bead Pack: 36.66 %
Hydrocarbon Pore Volume: 13825.0 cc
Initial Oil Saturation: 89.77 %
Irreducible Water Saturation: 10.23 %
Initial Model Temperature: 3.0 C
Water Feed Flow Rate: 199.3 cc
Steam Feed Flow Rate: 30.1 cc
Total Steam Injection Rate: 229.4 cc
Bottom Water % of Total Thick: 9.1 %

Sample	Sample Volume (cc)	Water Volume (cc)	Total Cumulative Production (cc)	(PV)	Cumulative Oil Produced (cc)	(%oioip)	Water in Sample(%)	Oil in Sample (%)	Inst. OSR	Cum. OSR
1	1875.0	1055.0	1875.0	0.1218	820.0	5.93%	56.27%	43.73%	0.4373	0.4373
2	2105.0	1750.0	3980.0	0.2584	1175.0	8.50%	83.14%	16.86%	0.1686	0.2952
3	1860.0	1570.0	5840.0	0.3792	1465.0	10.60%	84.41%	15.59%	0.1559	0.2509
4	1910.0	1665.0	7750.0	0.5032	1710.0	12.37%	87.17%	12.83%	0.1283	0.2206
5	1820.0	1580.0	9570.0	0.6214	1950.0	14.10%	86.81%	13.19%	0.1319	0.2038
6	1930.0	1690.0	11500.0	0.7468	2190.0	15.84%	87.56%	12.44%	0.1244	0.1904
7	2010.0	1790.0	13510.0	0.8773	2410.0	17.43%	89.05%	10.95%	0.1095	0.1784
8	1975.0	1745.0	15485.0	1.0055	2640.0	19.10%	88.35%	11.65%	0.1165	0.1705
9	1840.0	1650.0	17325.0	1.1250	2830.0	20.47%	89.67%	10.33%	0.1033	0.1633
10	1890.0	1685.0	19215.0	1.2477	3035.0	21.95%	89.15%	10.85%	0.1085	0.1579
11	1820.0	1530.0	21035.0	1.3659	3325.0	24.05%	84.07%	15.93%	0.1593	0.1581
12	1980.0	1815.0	23015.0	1.4945	3490.0	25.24%	91.67%	8.33%	0.0833	0.1516
13	1730.0	1605.0	24745.0	1.6068	3615.0	26.15%	92.77%	7.23%	0.0723	0.1461
14	1920.0	1800.0	26665.0	1.7315	3735.0	27.02%	93.75%	6.25%	0.0625	0.1401
15	1680.0	1590.0	28345.0	1.8406	3825.0	27.67%	94.64%	5.36%	0.0536	0.1349

Table 8.7 : Experimental Data For Run 32
Model Simulating the Aberfeldy Reservoir--Continuous Steamflood In Bottom Water Model
 Injection and Production From Upper Portion of Model

Pore Volume of Bead Pack: 15395.0 cc
 Porosity of Bead Pack: 36.65 %
 Hydrocarbon Pore Volume: 13625.0 cc
 Initial Oil Saturation: 88.50 %
 Irreducible Water Saturation: 11.50 %
 Initial Model Temperature: 3.0 C
 Water Feed Flow Rate: 199.3 cc
 Steam Feed Flow Rate: 30.1 cc
 Total Steam Injection Rate: 229.4 cc
 Bottom Water % of Total Thick: 2.3 %

Sample	Sample Volume (cc)	Water Volume (cc)	Total Cumulative Production (cc)	Total Cumulative Production (PV)	Cumulative Oil Produced (cc)	Cumulative Oil Produced (%o.oip)	Water in Sample(%)	Oil in Sample (%)	Inst. OSR	Cum. OSR
1	1910.0	1060.0	1910.0	0.1241	850.0	6.24%	55.50%	44.50%	0.4450	0.4450
2	1820.0	1590.0	3730.0	0.2423	1080.0	7.93%	87.36%	12.64%	0.1264	0.2895
3	1780.0	1435.0	5510.0	0.3579	1425.0	10.46%	80.62%	19.38%	0.1938	0.2586
4	1960.0	1685.0	7470.0	0.4852	1700.0	12.48%	85.97%	14.03%	0.1403	0.2276
5	1940.0	1700.0	9410.0	0.6112	1940.0	14.24%	87.63%	12.37%	0.1237	0.2062
6	1760.0	1565.0	11170.0	0.7256	2135.0	15.67%	88.92%	11.08%	0.1108	0.1911
7	1900.0	1725.0	13070.0	0.8490	2310.0	16.95%	90.79%	9.21%	0.0921	0.1767
8	2030.0	1855.0	15100.0	0.9808	2485.0	18.24%	91.38%	8.62%	0.0862	0.1646
9	1965.0	1840.0	17065.0	1.1085	2610.0	19.16%	93.64%	6.36%	0.0636	0.1529
10	1900.0	1790.0	18965.0	1.2319	2720.0	19.96%	94.21%	5.79%	0.0579	0.1434
11	1840.0	1740.0	20805.0	1.3514	2820.0	20.70%	94.57%	5.43%	0.0543	0.1355
12	1970.0	1860.0	22775.0	1.4794	2930.0	21.50%	94.42%	5.58%	0.0558	0.1286
13	1960.0	1870.0	24735.0	1.6067	3020.0	22.17%	95.41%	4.59%	0.0459	0.1221
14	2000.0	1920.0	26735.0	1.7366	3100.0	22.75%	96.00%	4.00%	0.0400	0.1160

Table 8.8 : Experimental Data For Run 33
Model Simulating the Aberfeldy Reservoir--Continuous Steamflood In Bottom Water Model
Injection Into Lower Portion of Model, Production Over Entire Interval

Pore Volume of Bead Pack: 15681.0 cc
Porosity of Bead Pack: 37.33 %
Hydrocarbon Pore Volume: 13595.0 cc
Initial Oil Saturation: 86.70 %
Irreducible Water Saturation: 13.30 %
Initial Model Temperature: 3.0 C
Water Feed Flow Rate: 199.3 cc
Steam Feed Flow Rate: 30.1 cc
Total Steam Injection Rate: 229.4 cc
Bottom Water % of Total Thick: 4.0 %

Sample	Sample Volume (cc)	Water Volume (cc)	Total Cumulative Production (cc)	Total Cumulative Production (PV)	Cumulative Oil Produced (cc)	(%o.oip)	Water in Sample(%)	Oil in Sample (%)	Inst. OSR	Cum. OSR
1	1875.0	1545.0	1875.0	0.1196	330.0	2.43%	82.40%	17.60%	0.1760	0.1760
2	2000.0	1700.0	3875.0	0.2471	630.0	4.63%	85.00%	15.00%	0.1500	0.1626
3	1800.0	1540.0	5675.0	0.3619	890.0	6.55%	85.56%	14.44%	0.1444	0.1568
4	2145.0	1855.0	7820.0	0.4987	1180.0	8.68%	86.48%	13.52%	0.1352	0.1509
5	1960.0	1600.0	9780.0	0.6237	1540.0	11.33%	81.63%	18.37%	0.1837	0.1575
6	2075.0	1795.0	11855.0	0.7560	1820.0	13.39%	86.51%	13.49%	0.1349	0.1535
7	1880.0	1680.0	13735.0	0.8759	2020.0	14.86%	89.36%	10.64%	0.1064	0.1471
8	2015.0	1800.0	15750.0	1.0044	2235.0	16.44%	89.33%	10.67%	0.1067	0.1419
9	1985.0	1750.0	17735.0	1.1310	2470.0	18.17%	88.16%	11.84%	0.1184	0.1393
10	1920.0	1765.0	19655.0	1.2534	2625.0	19.31%	91.93%	8.07%	0.0807	0.1336
11	2040.0	1890.0	21695.0	1.3835	2775.0	20.41%	92.65%	7.35%	0.0735	0.1279
12	1880.0	1760.0	23575.0	1.5034	2895.0	21.29%	93.62%	6.38%	0.0638	0.1228
13	2075.0	1955.0	25650.0	1.6357	3015.0	22.18%	94.22%	5.78%	0.0578	0.1175
14	1920.0	1820.0	27570.0	1.7582	3115.0	22.91%	94.79%	5.21%	0.0521	0.1130

Table 8.9 : Experimental Data For Run 39
Model Simulating the Aberfeldy Reservoir--Continuous Steamflood in Bottom Water Model
 Injection over entire well; Production from top half of model.

Pore Volume of Bead Pack: 15580.0 cc
 Porosity of Bead Pack: 37.09 %
 Hydrocarbon Pore Volume: 13400.0 cc
 Initial Oil Saturation: 86.01 %
 Irreducible Water Saturation: 13.99 %
 Initial Model Temperature: 3.0 C
 Water Feed Flow Rate: 199.7 cc
 Steam Feed Flow Rate: 30.4 cc
 Total Steam Injection Rate: 230.1 cc
 Vol. of Bottom Water in Mode: 1944.5 cc
 Bottom Water Thickness: 12.48 % of Total Thickness

Sample	Sample Volume (cc)	Water Volume (cc)	Total Cumulative Production (cc)	(PV)	Cumulative Oil Produced (cc)	(%oioip)	Water in Sample(%)	Oil in Sample (%)	Inst. OSR	Cum. OSR
1	1895.0	1770.0	1895.0	0.1216	125.0	0.93%	93.40%	6.60%	0.0660	0.0660
2	2130.0	1880.0	4025.0	0.2583	375.0	2.80%	88.26%	11.74%	0.1174	0.0932
3	1910.0	1620.0	5935.0	0.3809	665.0	4.96%	84.82%	15.18%	0.1518	0.1120
4	2050.0	1845.0	7985.0	0.5125	870.0	6.49%	90.00%	10.00%	0.1000	0.1090
5	1990.0	1750.0	9975.0	0.6402	1110.0	8.28%	87.94%	12.06%	0.1206	0.1113
6	2005.0	1835.0	11980.0	0.7689	1280.0	9.55%	91.52%	8.48%	0.0848	0.1068
7	1930.0	1725.0	13910.0	0.8928	1485.0	11.08%	89.38%	10.62%	0.1062	0.1068
8	1965.0	1825.0	15875.0	1.0189	1625.0	12.13%	92.88%	7.12%	0.0712	0.1024
9	1910.0	1780.0	17785.0	1.1415	1755.0	13.10%	93.19%	6.81%	0.0681	0.0987
10	2020.0	1985.0	19805.0	1.2712	1790.0	13.36%	98.27%	1.73%	0.0173	0.0904
11	1920.0	1810.0	21725.0	1.3944	1900.0	14.18%	94.27%	5.73%	0.0573	0.0875
12	2020.0	1905.0	23745.0	1.5241	2015.0	15.04%	94.31%	5.69%	0.0569	0.0849
13	2030.0	1915.0	25775.0	1.6544	2130.0	15.90%	94.33%	5.67%	0.0567	0.0826
14	2000.0	1880.0	27775.0	1.7827	2250.0	16.79%	94.00%	6.00%	0.0600	0.0810

of the model. The volume of bottom water which is produced during the experiment can be determined in a similar manner.

Both Runs 31 and 32 involved injecting steam into the upper portion of the model. The production response of the two experiments is similar, with 27.7% of the original oil in place being produced in Run 31 after a total production of 1.84 pore volumes. In Run 32, 22.75% of the original oil in place was produced after a total production of 1.87 pore volumes. Run 33 was conducted by injecting steam into the lower portion of the model, into the bottom water layer. The recovery for this run was 22.91% ooip after a total production of 1.76 pore volumes. Run 39 was conducted by injecting steam over the entire formation while producing from the top half of the formation.

It is obvious from the results of these experiments, in comparison to steamflood experiments in homogeneous models, that the bottom water had a detrimental effect on the oil recovery response of the steamflood, particularly for Run 39 in which the bottom water thickness was 12.5% of the total model thickness. In this experiment, the recovery was only 16.8% of the original oil in place after 1.8 pore volumes of total production. The average recovery from a homogeneous model to a similar point was about 33% ooip.

Gas Injection Experiments

Another process, which may be suitable for recovering oil from reservoirs underlain by bottom water, involves injecting a small volume of inert gas into the reservoir prior to steam injection. It was hypothesized that this process will create a flow path for the subsequent steam injection away from the bottom water layer, thus minimizing the heat sink effect of bottom water. This strategy also has the advantage of dramatically improving steam injectivity and thus it may also be suitable for reservoirs where the desired steam injectivity cannot be achieved.

These experiments involved the injection of nitrogen gas into the model, prior to steamflooding, the purpose of which was to create an initial gas saturation within the model to promote the segregation of steam in thin formations to the upper part of the formation.

Nitrogen gas was injected at 15 kPa (2 psia) into the model, with a deep vacuum applied at the production, typical of all experiments. The breakthrough of gas was observed almost immediately after injection. Gas injection was continued until little or no further oil production was observed, typically four to five minutes (or approximately half a year in the prototype).

At the termination of gas injection, the system was prepared for steam injection, and steam injection was initiated when the steam had stabilized at the desired temperature.

Gas Injection Experiments--Homogeneous Models

Runs 24, 25, 28 and 29 were gas injection experiments conducted in homogeneous models (i.e. no bottom water).

The experimental parameters and recovery response for Run 24 are given in Table 8.10 and temperature profiles for this run for the injection of 0.25, 0.50, 0.75, 1.00, 1.50, and 2.00 pore volumes of steam are given as Figures 8.1, 8.2, 8.3, 8.4, 8.5, and 8.6, respectively. During this experiment, injection was into the lower portion of the model.

The first two temperature profiles, Figures 8.1 and 8.2 for the injection of 0.25 and 0.50 pore volumes of steam, respectively, show that the heat front initially advanced in the lower portion of the model, along an eccentric path. Figures 8.3 through 8.6, for the injection of 0.75, 1.00, 1.50, and 2.00 pore volumes of steam, respectively, show a more symmetrical pattern of heat movement through the model. They continue to indicate that the heat front is advancing through the lower portion of the model. The injection into the lower portion of the model may have resulted in the gas channeling along the bottom of the model. When steam injection was initiated, the heat front likely followed the same path.

Run 25 was conducted in a manner similar to that of Run 24, with the important difference being that the initial gas injection and subsequent steam injection was into the upper portion of the bead pack. As before, nitrogen gas was injected at 15 kPa into the mode, with a deep vacuum applied at the production well. The breakthrough of gas was observed almost immediately after injection. Gas injection was continued for ten minutes at

Table 8.10 : Experimental Data For Run 24
Model Simulating the Aberfeldy Reservoir--Continuous Steamflood Following Gas Injection In Homogeneous Model

Pore Volume of Bead Pack: 14080.0 cc
 Porosity of Bead Pack: 33.52 %
 Hydrocarbon Pore Volume: 13240.0 cc
 Initial Oil Saturation: 94.03 %
 Irreducible Water Saturation: 5.97 %
 Initial Model Temperature: 3.0 C
 Water Feed Flow Rate: 199.3 cc
 Steam Feed Flow Rate: 30.1 cc
 Total Steam Injection Rate: 229.4 cc
 Gas Cap Volume: 220.0 cc

Sample	Sample Volume (cc)	Water Volume (cc)	Total Cumulative Production (cc)	Total Cumulative Production (PV)	Cumulative Oil Produced (cc)	(%oosp)	Water in Sample(%)	Oil in Sample (%)	Inst. OSR	Cum. OSR
1	220.0	30.0	220.0	0.0156	190.0	1.44%	13.64%	86.36%	0.8636	0.8636
2	2010.0	790.0	2230.0	0.1584	1410.0	10.65%	39.30%	60.70%	0.6070	0.6323
3	1980.0	1335.0	4210.0	0.2990	2055.0	15.52%	67.42%	32.58%	0.3258	0.4881
4	2030.0	1715.0	6240.0	0.4432	2370.0	17.90%	84.48%	15.52%	0.1552	0.3798
5	1965.0	1705.0	8205.0	0.5827	2630.0	19.86%	86.77%	13.23%	0.1323	0.3205
6	1955.0	1745.0	10150.0	0.7216	2840.0	21.45%	89.26%	10.74%	0.1074	0.2795
7	1950.0	1790.0	12110.0	0.8601	3000.0	22.66%	91.79%	8.21%	0.0821	0.2477
8	1975.0	1820.0	14085.0	1.0004	3155.0	23.83%	92.15%	7.85%	0.0785	0.2240
9	1960.0	1835.0	16045.0	1.1396	3280.0	24.77%	93.62%	6.38%	0.0638	0.2044
10	2040.0	1900.0	18085.0	1.2844	3420.0	25.83%	93.14%	6.86%	0.0686	0.1891
11	1960.0	1850.0	20045.0	1.4237	3530.0	26.66%	94.39%	5.61%	0.0561	0.1761
12	2050.0	1910.0	22095.0	1.5692	3670.0	27.72%	93.17%	6.83%	0.0683	0.1661
13	1950.0	1840.0	24045.0	1.7077	3780.0	28.55%	94.36%	5.64%	0.0564	0.1572
14	2070.0	1935.0	26115.0	1.8548	3915.0	29.57%	93.48%	6.52%	0.0652	0.1499

Figure 8.1

Run 24: Gas Inj Run in Aberfeldy Model

Temperature Profile for
0.25 Pore Volumes Injected

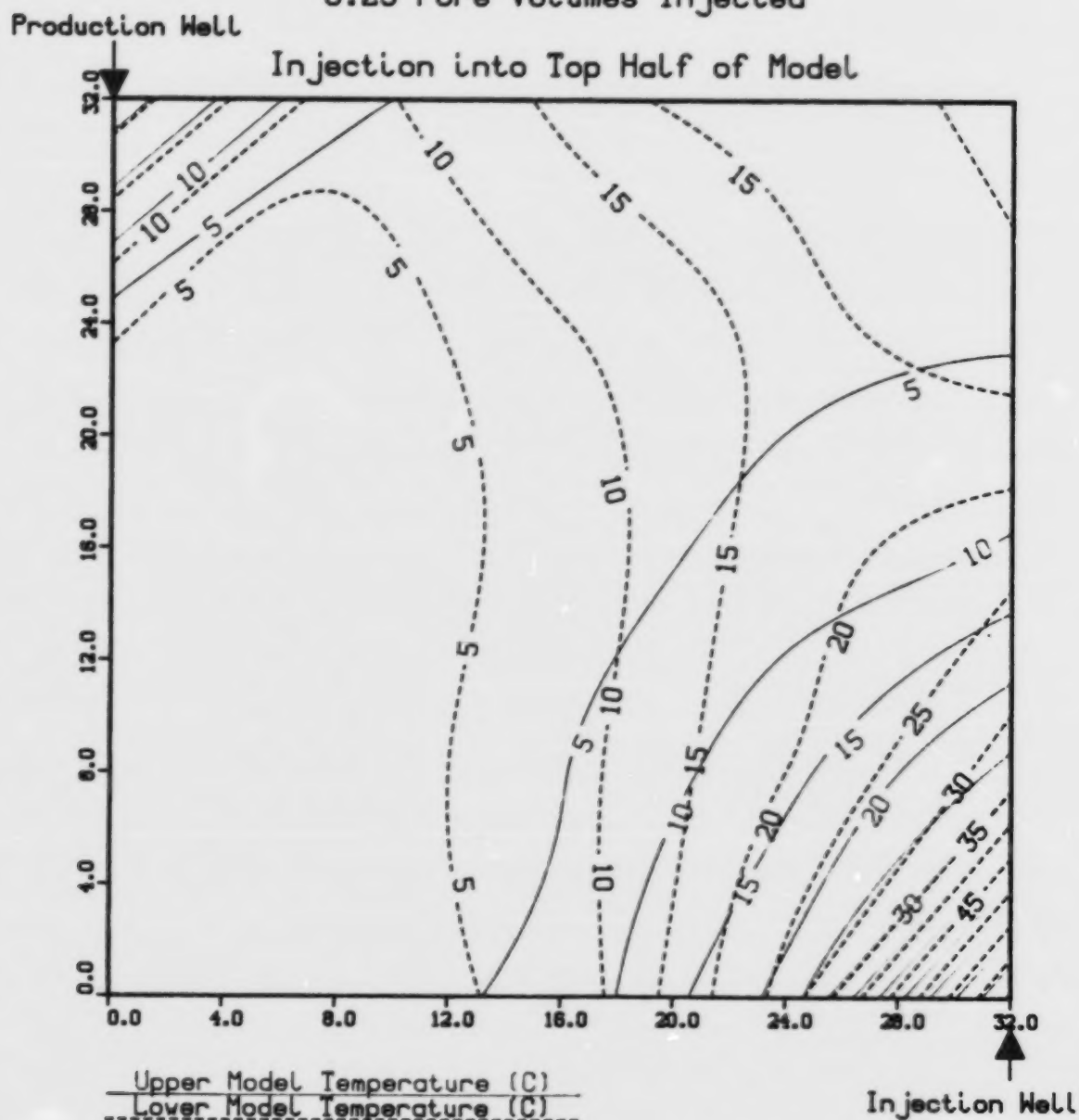


Figure 8.2

Run 24: Gas Inj Run in Aberfeldy Model

Temperature Profile for
0.50 Pore Volumes Injected

Production Well

Injection into Top Half of Model

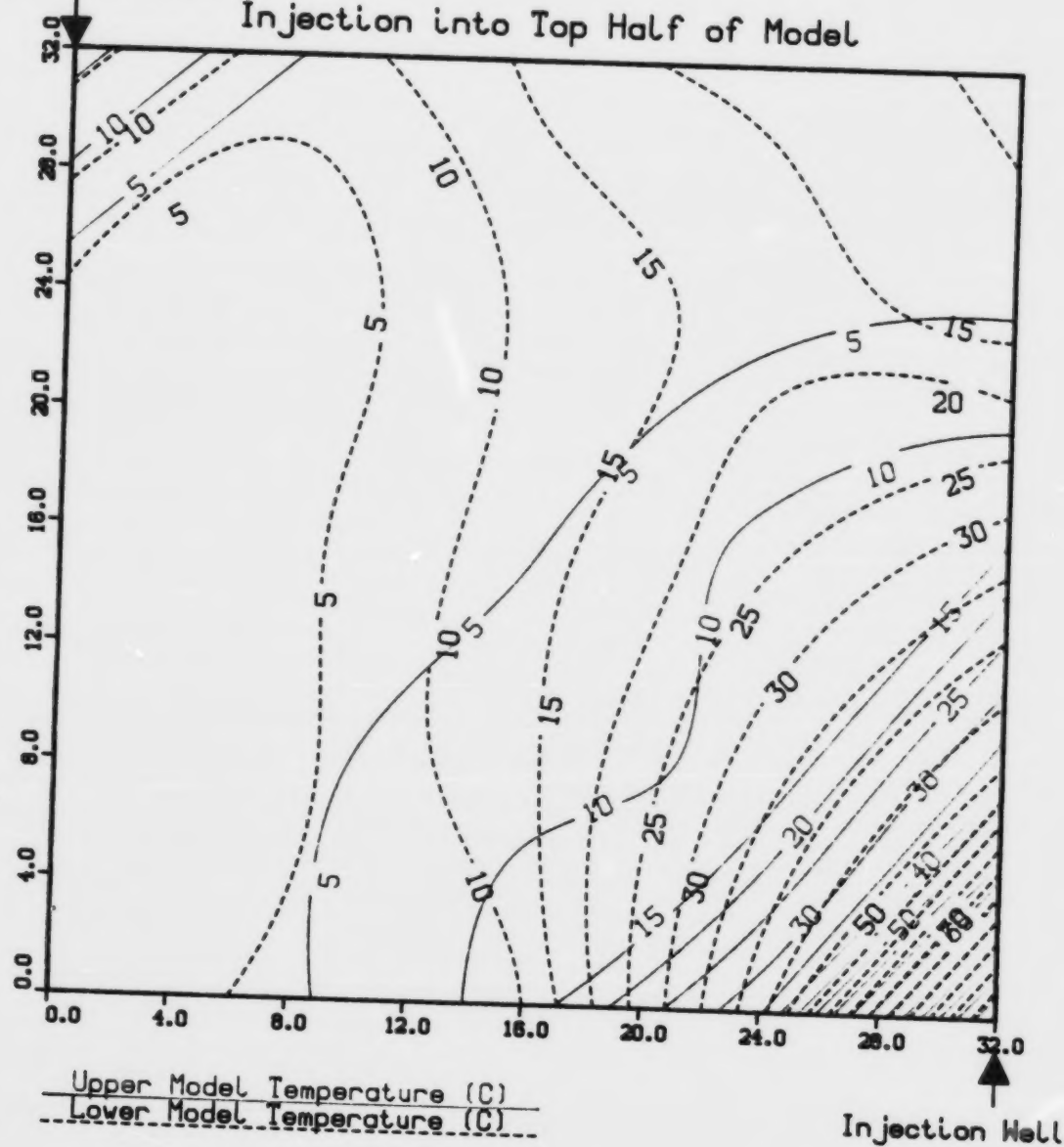


Figure 8.3

Run 24: Gas Inj Run in Aberfeldy Model

Temperature Profile for
0.75 Pore Volumes Injected

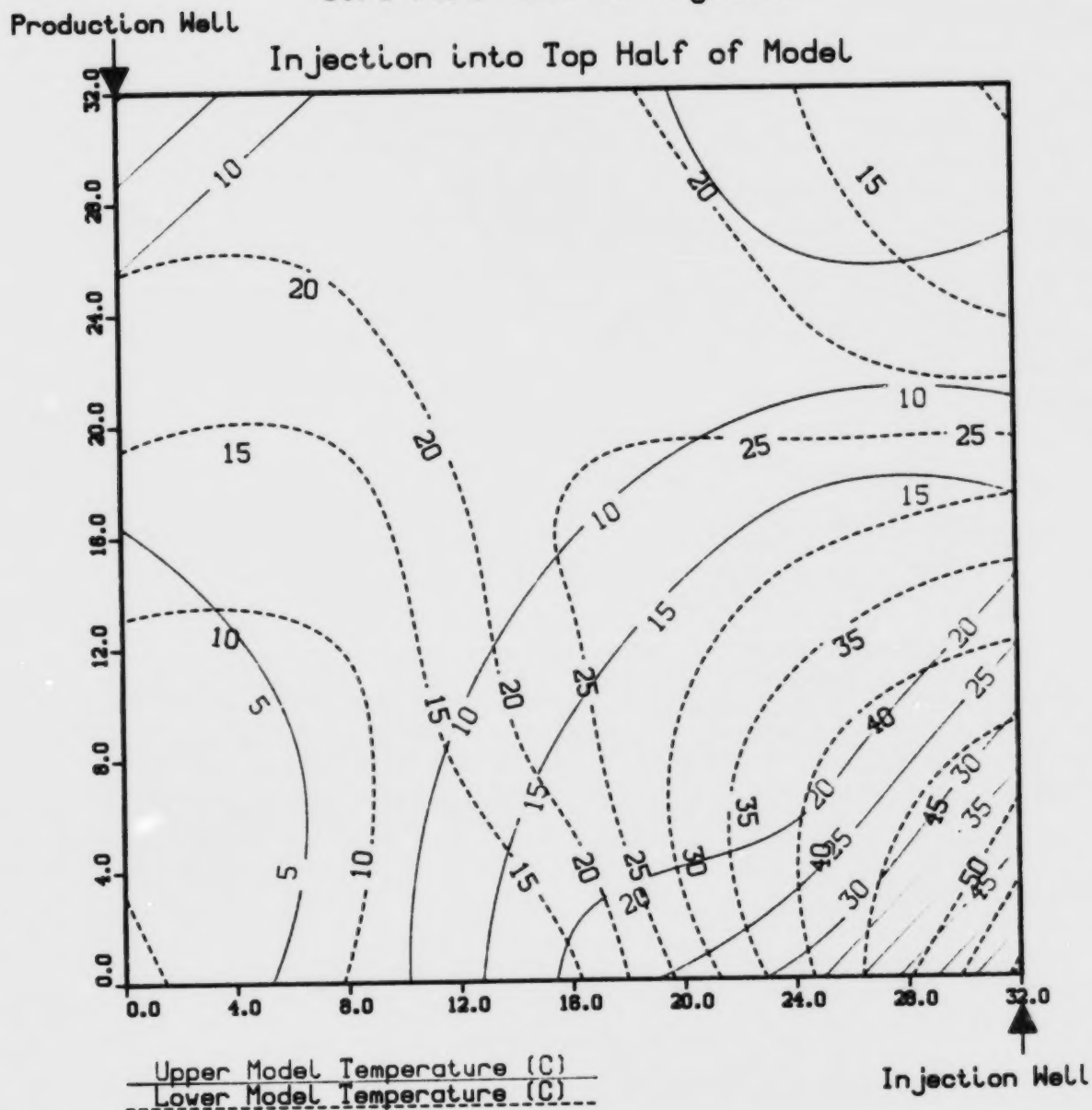


Figure 8.4

Run 24: Gas Inj Run in Aberfeldy Model

Temperature Profile for
1.00 Pore Volumes Injected

Production Well

Injection into Top Half of Model

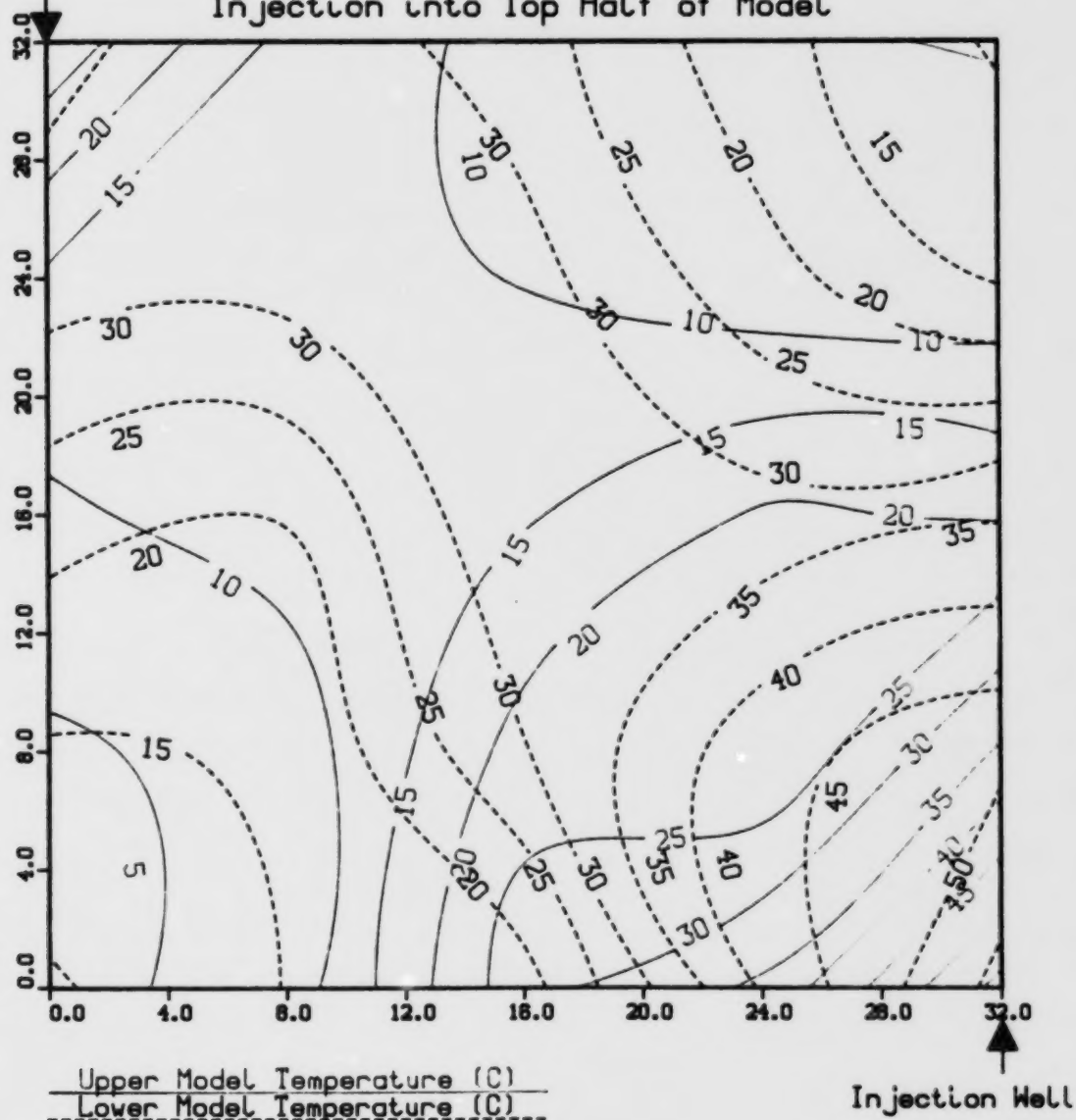


Figure 8.5

Run 24: Gas Inj Run in Aberfeldy Model

Temperature Profile for
1.50 Pore Volumes Injected

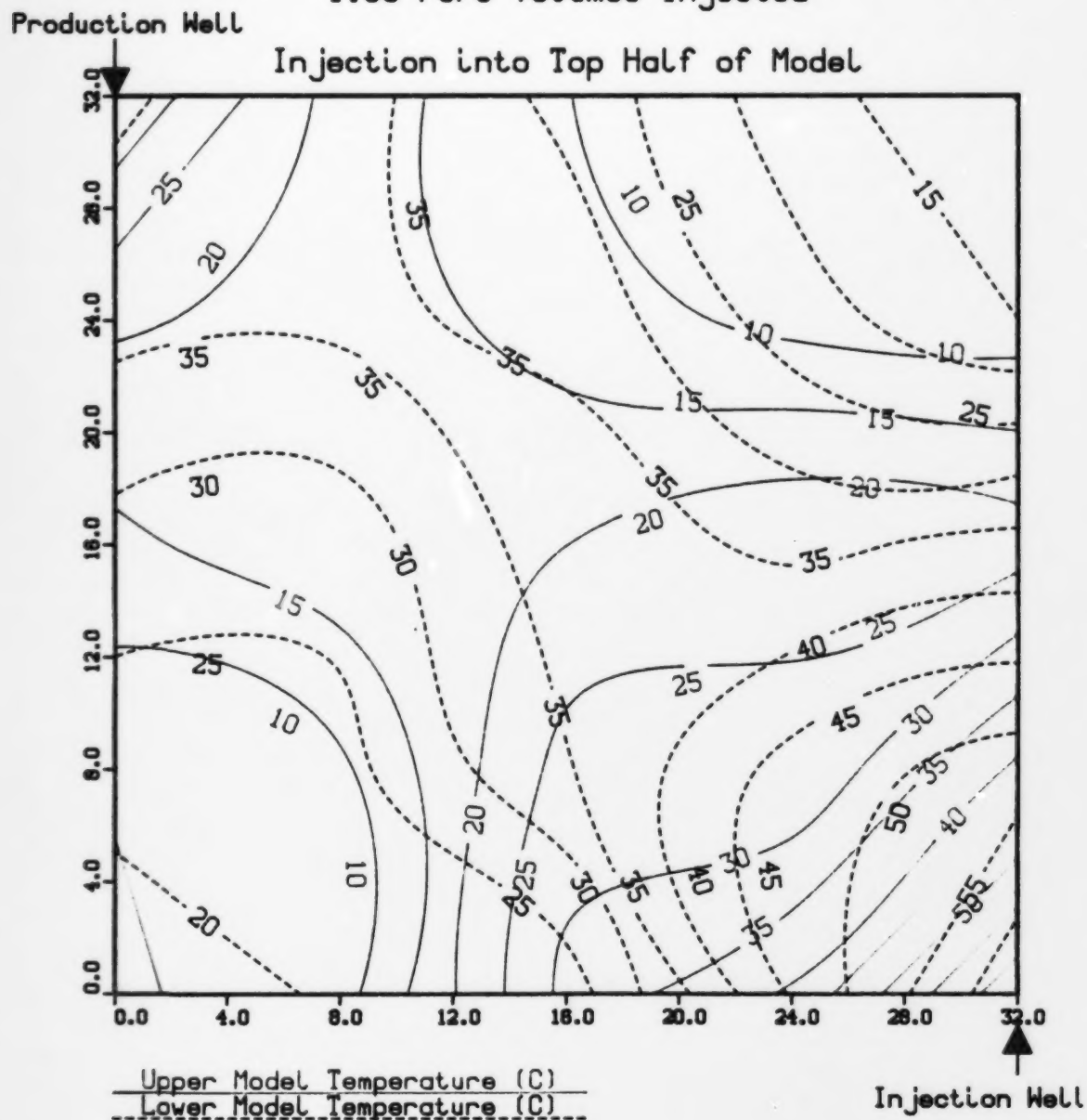


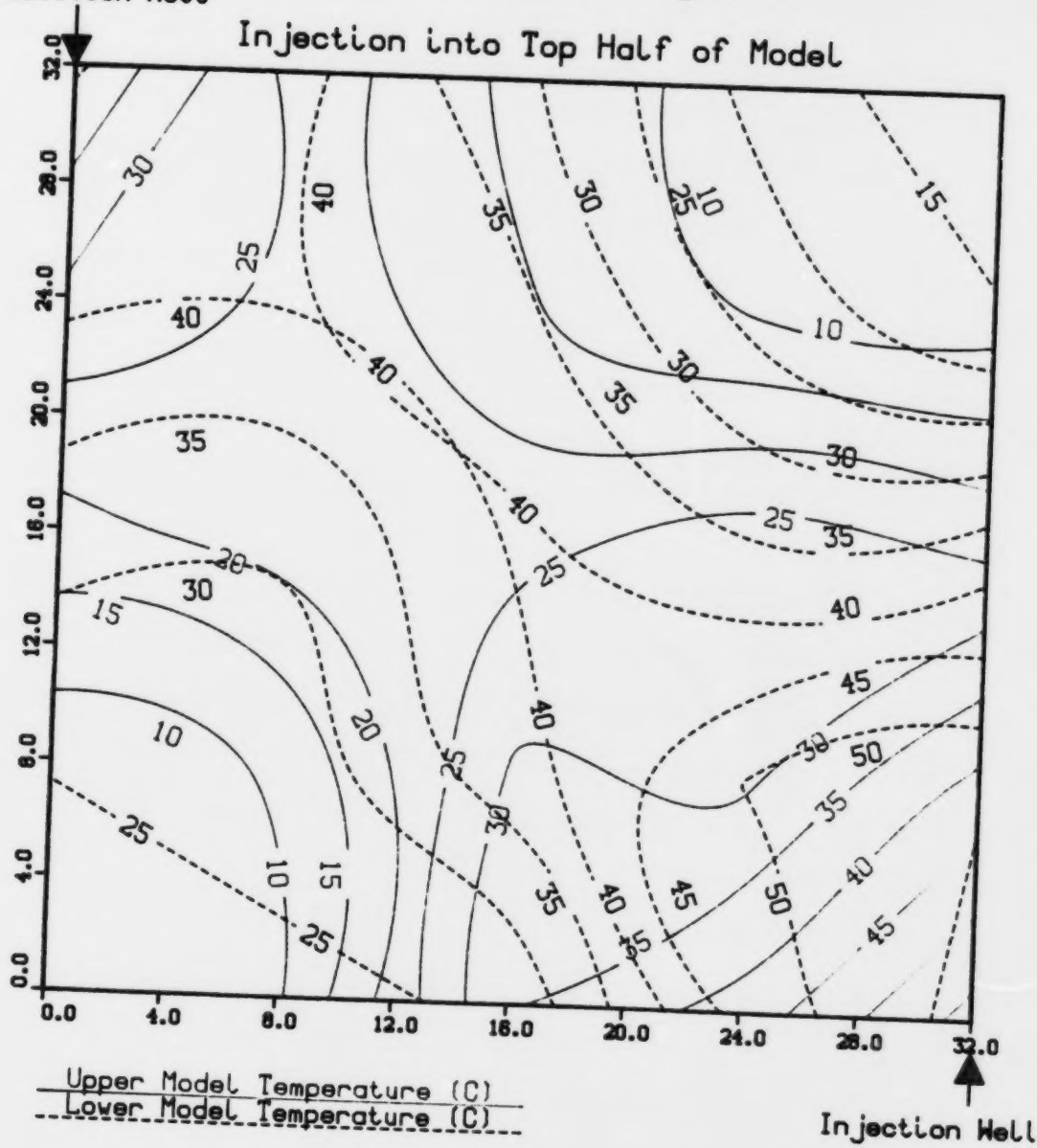
Figure 8.6

Run 24: Gas Inj Run in Aberfeldy Model

Temperature Profile for
2.00 Pore Volumes Injected

Production Well

Injection into Top Half of Model



which point 200 cc of oil had been recovered, giving an average gas saturation in the model of 1.43% at this point.

At the termination of gas injection, the system was prepared for steam injection. Steam injection into the upper part of the model was begun nine minutes later, when the steam had stabilized at the desired temperature. A brief fill-up period was observed; about three minutes (690 cc).

The experimental parameters for Run 25 are summarized in Table 8.11. The table also shows the recovery response of the experiment as a function of cumulative injection. The final recovery was 26.58% of the original oil in place after 1.85 pore volumes of steam had been injected. Temperature profiles for this experiment are included as Figures 8.7, 8.8, 8.9, 8.10, and 8.11, for the injection of 0.25, 0.50, 0.75, 1.00, and 1.50 pore volumes of steam, respectively. These profiles reveal that unlike Run 24, the heat front advance in the upper portion of the model in Run 25.

Run 29 also involved injecting gas into a homogeneous model to establish a flow channel for the steam, and then steamflooding the model. Injection was into the upper half of the model, while production was from the entire model thickness. Gas was injected at 14 kPa (2 psia) for five minutes (approximately 0.45 prototype years) at which point the instantaneous oil production was negligible. Table 8.12 gives the experimental parameters for this run and shows the production response of the steamflood which followed the gas injection. It can be seen that the cumulative oil production was 27.34% of the original oil in place after 1.92 pore volumes of steam were injected. The temperature profiles for this run are given as Figures 8.12 through 8.17 for 0.25, 0.50, 0.75, 1.00, 1.25, and 1.50 pore volumes of steam, respectively.

Examination of the temperature profiles for Run 29 reveal that the injected steam initially advances through the upper portion of the model. This trend is observed until approximately 1.0 pore volumes of steam have been injected, at which time the temperature within the lower layer of the model appears to be similar to that in the upper layer.

Model Simulating the Aberfeldy Reservoir--Continuous Steamflood Following Gas Injection In Homogeneous Model

Table 8.11 : Experimental Data For Run 25
Injection into Upper Portion of Model

Pore Volume of Bead Pack: 14005.0 cc
Porosity of Bead Pack: 33.34 %
Hydrocarbon Pore Volume: 13260.0 cc
Initial Oil Saturation: 94.68 %
Irreducible Water Saturation: 5.32 %
Initial Model Temperature: 3.0 C
Water Feed Flow Rate: 199.3 cc
Steam Feed Flow Rate: 30.1 cc
Total Steam Injection Rate: 229.4 cc
Gas Cap Volume: 200.0 cc

Sample	Sample Volume (cc)	Water Volume (cc)	Total Cumulative Production (cc)	Total Cumulative Production (PV)	Cumulative Oil Produced (cc)	Cumulative Oil Produced (%oioip)	Water in Sample(%)	Oil in Sample (%)	Inst. OSR	Cum. OSR
1	200.0	0.0	200.0	0.0143	200.0	1.51%	0.00%	100.00%	1.0000	1.0000
2	1915.0	1420.0	2115.0	0.1510	695.0	5.24%	74.15%	25.85%	0.2585	0.3286
3	1965.0	1675.0	4080.0	0.2913	985.0	7.43%	85.24%	14.76%	0.1476	0.2414
4	1925.0	1620.0	6005.0	0.4288	1290.0	9.73%	84.16%	15.84%	0.1584	0.2148
5	1960.0	1700.0	7965.0	0.5687	1550.0	11.69%	86.73%	13.27%	0.1327	0.1946
6	1935.0	1640.0	9900.0	0.7069	1845.0	13.91%	84.75%	15.25%	0.1525	0.1864
7	2030.0	1715.0	11930.0	0.8518	2160.0	16.29%	84.48%	15.52%	0.1552	0.1811
8	1955.0	1645.0	13885.0	0.9914	2470.0	18.63%	86.89%	15.86%	0.1586	0.1779
9	2060.0	1790.0	15945.0	1.1385	2740.0	20.66%	87.36%	13.11%	0.1311	0.1718
10	1740.0	1520.0	17685.0	1.2628	2960.0	22.32%	91.90%	12.64%	0.1264	0.1674
11	2100.0	1930.0	19785.0	1.4127	3130.0	23.60%	92.82%	8.10%	0.0810	0.1582
12	2020.0	1875.0	21805.0	1.5569	3275.0	24.70%	93.40%	7.18%	0.0718	0.1502
13	2120.0	1980.0	23925.0	1.7083	3415.0	25.75%	94.58%	6.60%	0.0660	0.1427
14	2030.0	1920.0	25955.0	1.8533	3525.0	26.58%		5.42%	0.0542	0.1358

Figure 8.7

Run 25: Gas Inj Run in Aberfeldy Model

Temperature Profile for
0.25 Pore Volumes Injected

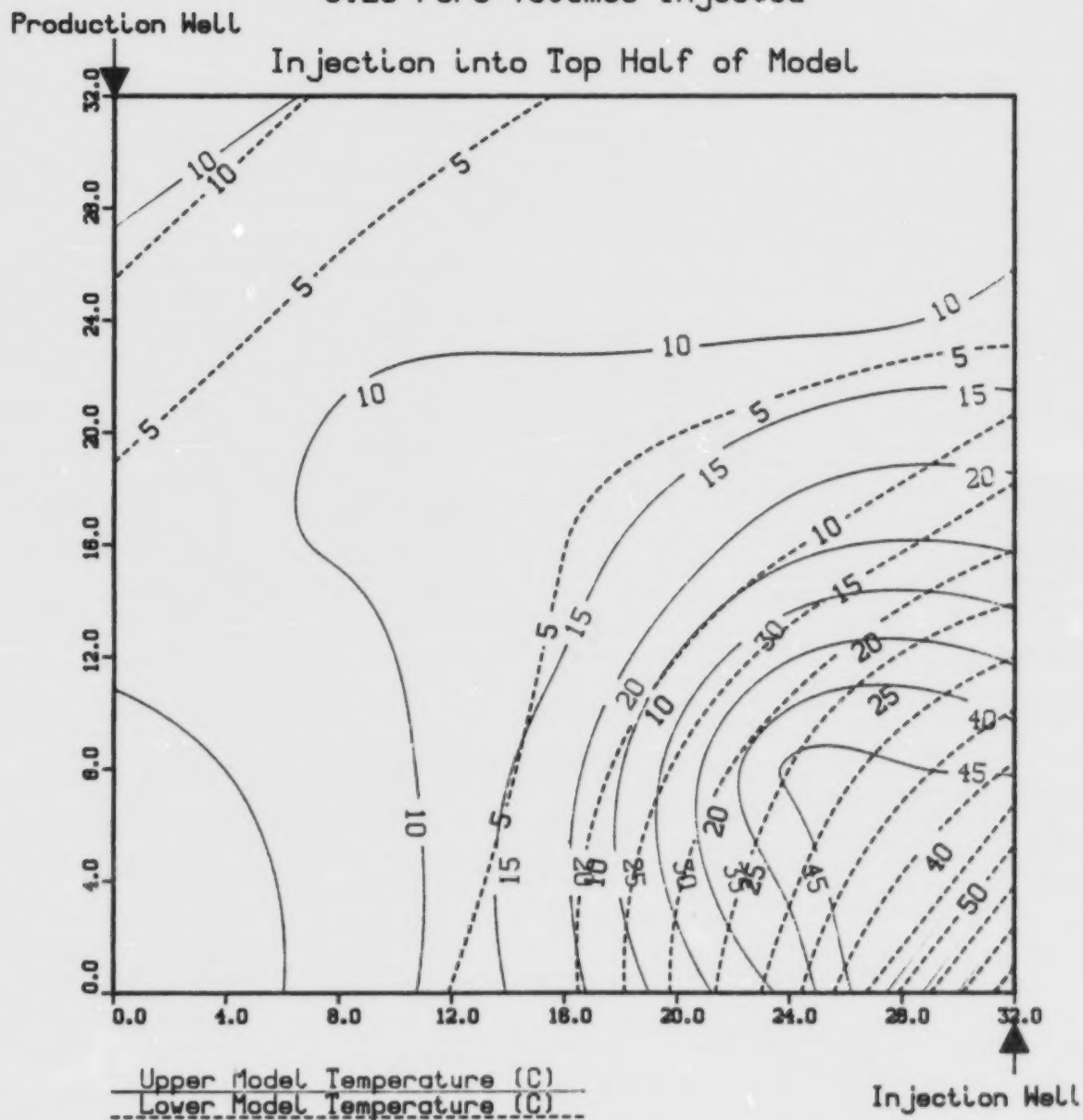


Figure 8.8

Run 25: Gas Inj Run in Aberfeldy Model

Temperature Profile for
0.50 Pore Volumes Injected

Production Well

Injection into Top Half of Model

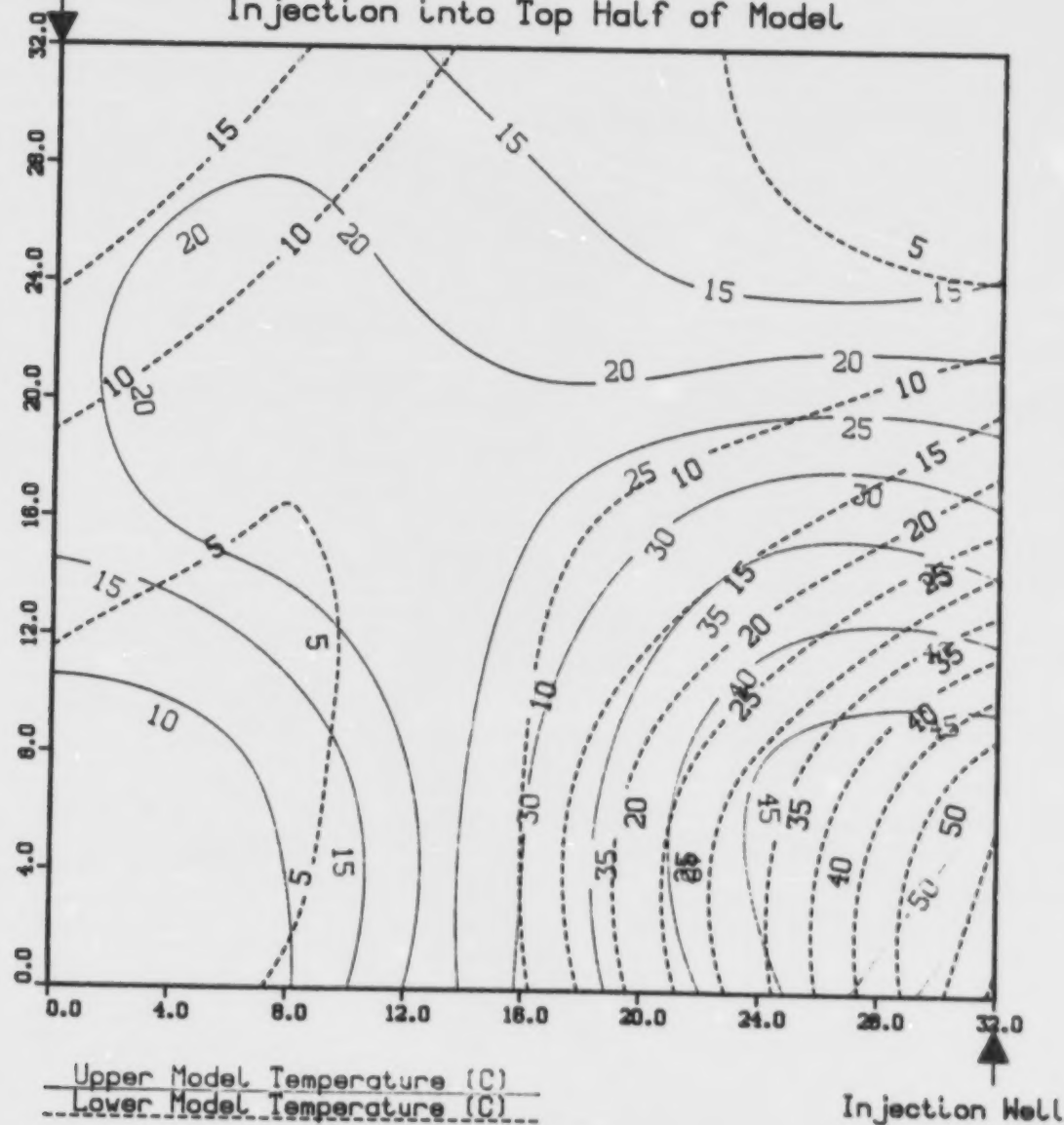


Figure 8.9

Run 25: Gas Inj Run in Aberfeldy Model

Temperature Profile for
0.75 Pore Volumes Injected

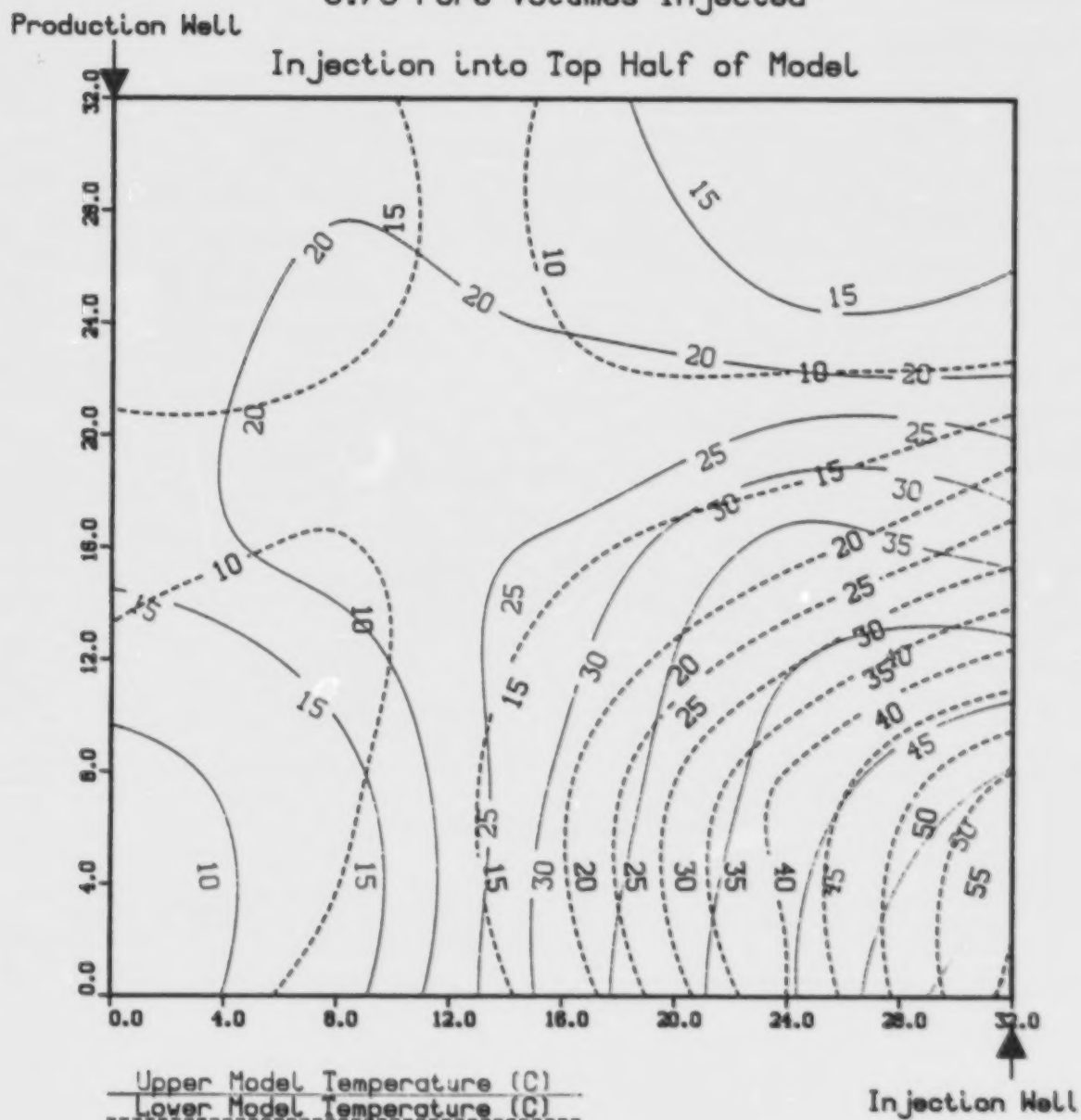


Figure 8.10

Run 25: Gas Inj Run in Aberfeldy Model

Temperature Profile for
1.00 Pore Volumes Injected

Production Well

Injection into Top Half of Model

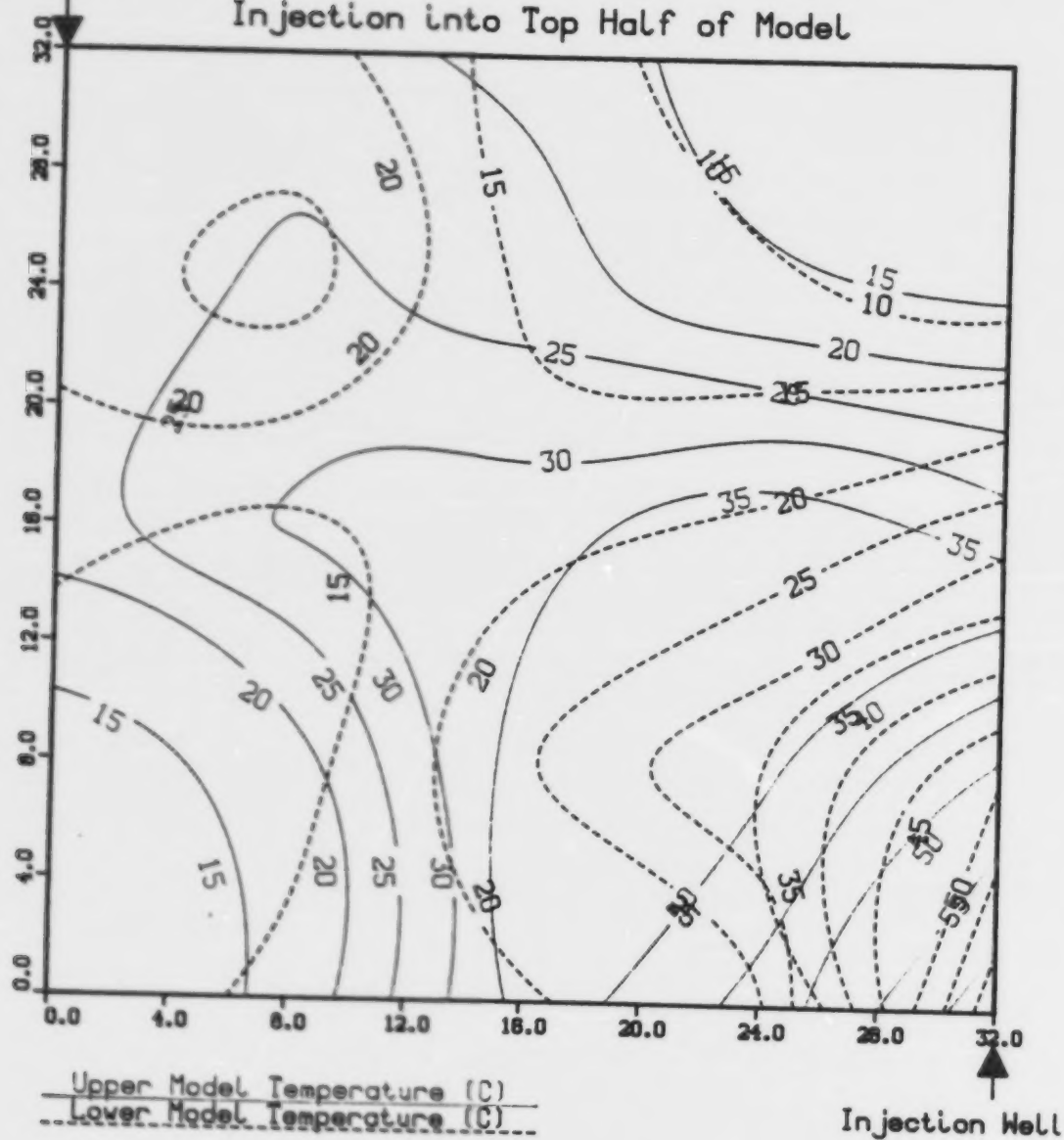


Figure 8.11

Run 25: Gas Inj Run in Aberfeldy Model

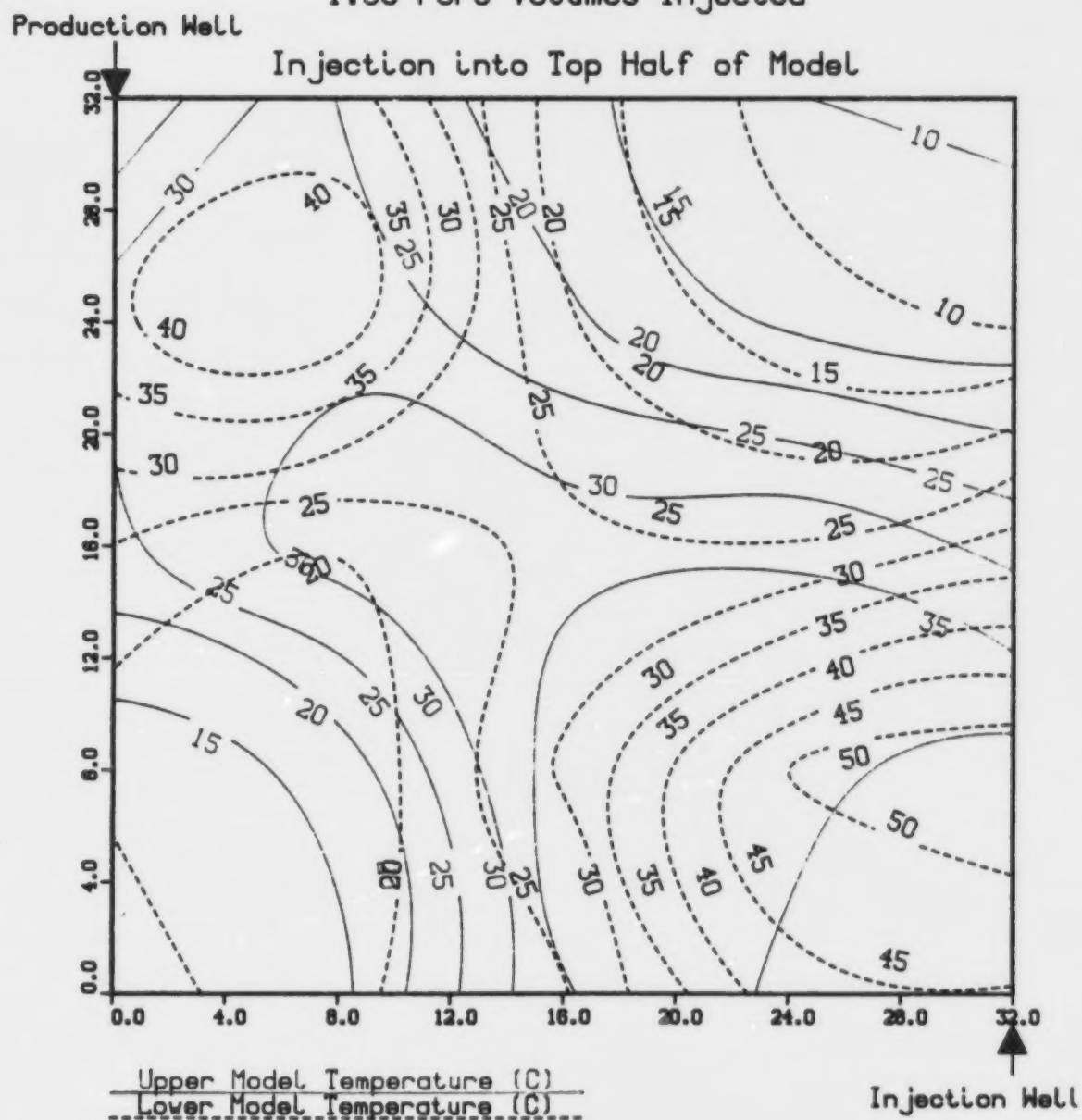
Temperature Profile for
1.50 Pore Volumes Injected

Table 8.12 : Experimental Data For Run 29
Model Simulating the Aberfeldy Reservoir--Continuous Steamflood Following Gas Injection In Homogeneous Model

Pore Volume of Bead Pack: 14070.0 cc
 Porosity of Bead Pack: 33.50 %
 Hydrocarbon Pore Volume: 12580.0 cc
 Initial Oil Saturation: 89.41 %
 Irreducible Water Saturation: 10.59 %
 Initial Model Temperature: 3.0 C
 Water Feed Flow Rate: 199.3 cc
 Steam Feed Flow Rate: 30.1 cc
 Total Steam Injection Rate: 229.4 cc
 Gas Cap Volume: 140.0 cc

Sample	Sample Volume (cc)	Water Volume (cc)	Total Cumulative Production (cc)	Total Cumulative Production (PV)	Cumulative Oil Produced (cc)	Cumulative Oil Produced (%ooiip)	Water in Sample(%)	Oil in Sample (%)	Inst. OSR	Cum. OSR
1	140.0	0.0	140.0	0.0100	140.0	1.11%	0.00%	100.00%	1.0000	1.0000
2	2090.0	1700.0	2230.0	0.1585	530.0	4.21%	81.34%	18.66%	0.1866	0.2377
3	1800.0	1490.0	4030.0	0.2864	840.0	6.68%	82.78%	17.22%	0.1722	0.2084
4	1920.0	1595.0	5950.0	0.4229	1165.0	9.26%	83.07%	16.93%	0.1693	0.1958
5	1870.0	1540.0	7820.0	0.5558	1495.0	11.88%	82.35%	17.65%	0.1765	0.1912
6	1840.0	1630.0	9660.0	0.6866	1705.0	13.55%	88.59%	11.41%	0.1141	0.1765
7	1850.0	1550.0	11510.0	0.8181	2005.0	15.94%	83.78%	16.22%	0.1622	0.1742
8	2005.0	1780.0	13515.0	0.9606	2230.0	17.73%	88.78%	11.22%	0.1122	0.1650
9	1990.0	1800.0	15505.0	1.1020	2420.0	19.24%	90.45%	9.55%	0.0955	0.1561
10	1870.0	1700.0	17375.0	1.2349	2590.0	20.59%	90.91%	9.09%	0.0909	0.1491
11	1970.0	1830.0	19345.0	1.3749	2730.0	21.70%	92.89%	7.11%	0.0711	0.1411
12	1980.0	1770.0	21325.0	1.5156	2940.0	23.37%	89.39%	10.61%	0.1061	0.1379
13	1810.0	1720.0	23135.0	1.6443	3030.0	24.09%	95.03%	4.97%	0.0497	0.1310
14	1930.0	1650.0	25065.0	1.7814	3310.0	26.31%	85.49%	14.51%	0.1451	0.1321
15	1950.0	1820.0	27015.0	1.9200	3440.0	27.34%	93.33%	6.67%	0.0667	0.1273

Figure 8.12

Run 29: Gas Inj.-Steamflood of Model

Temperature Profile for
0.25 Pore Volumes Injected

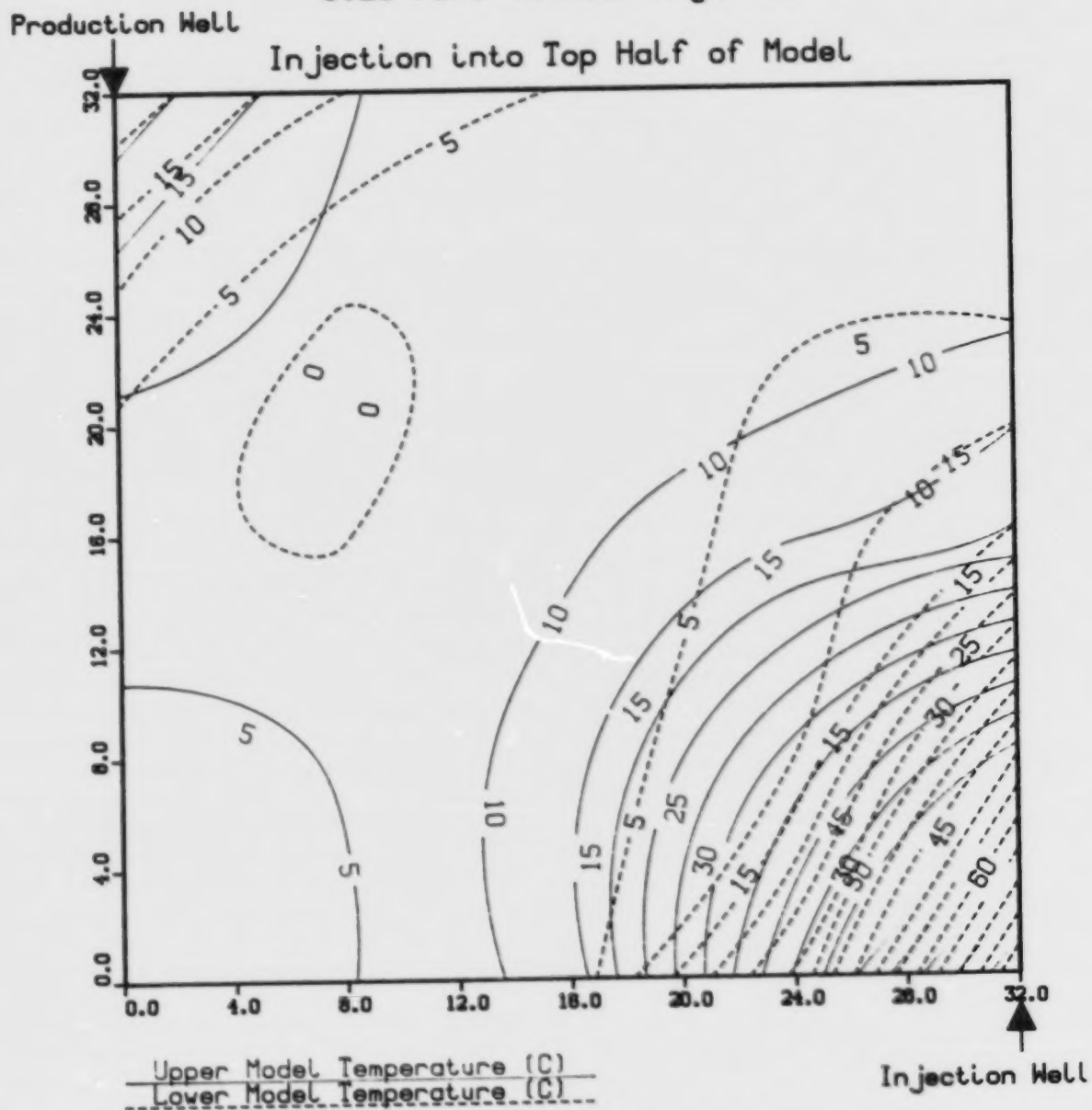


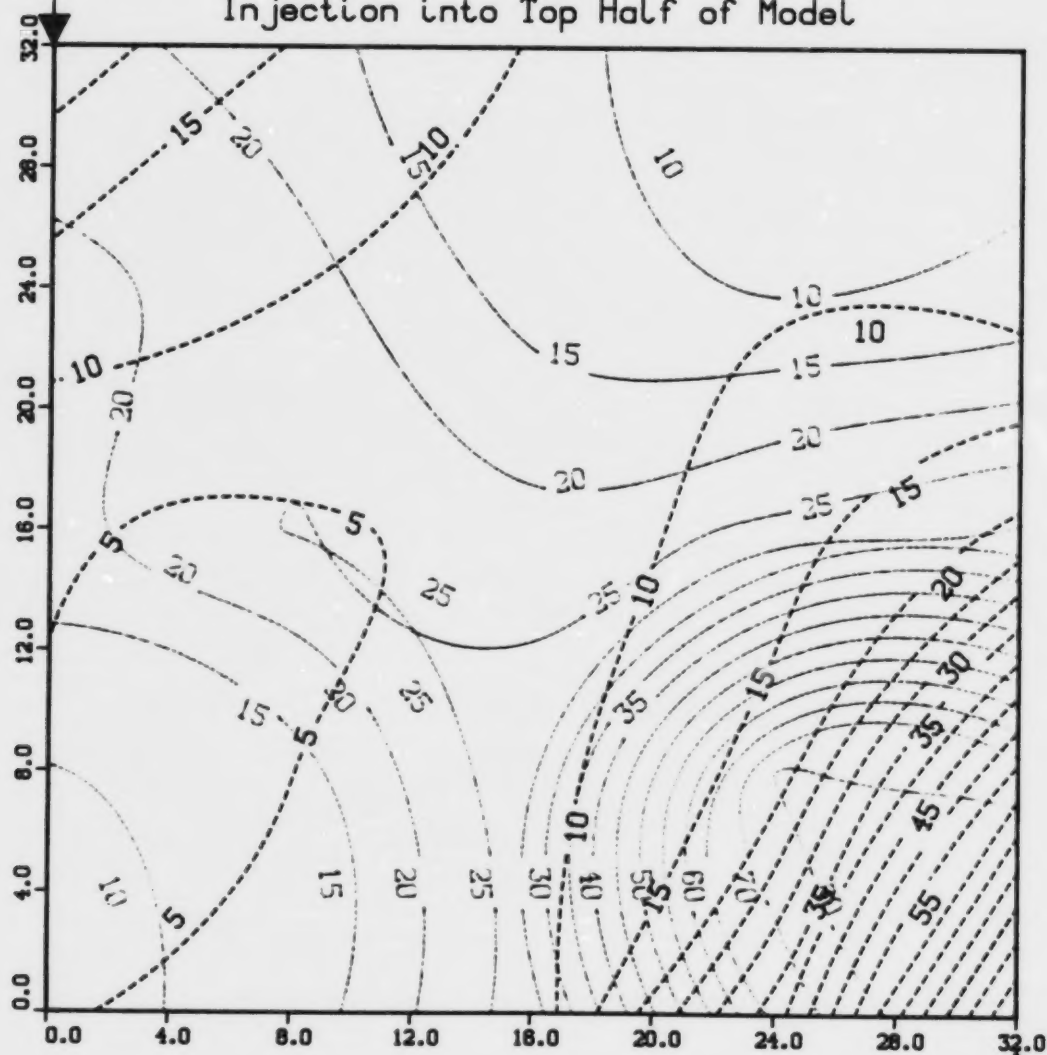
Figure 8.13

Run 29: Gas Inj.-Steamflood of Model

Temperature Profile for
0.50 Pore Volumes Injected

Production Well

Injection into Top Half of Model



Upper Model Temperature (°C)

Lower Model Temperature (°C)

Injection Well

Figure 8.14

Run 29: Gas Inj.-Steamflood of Model

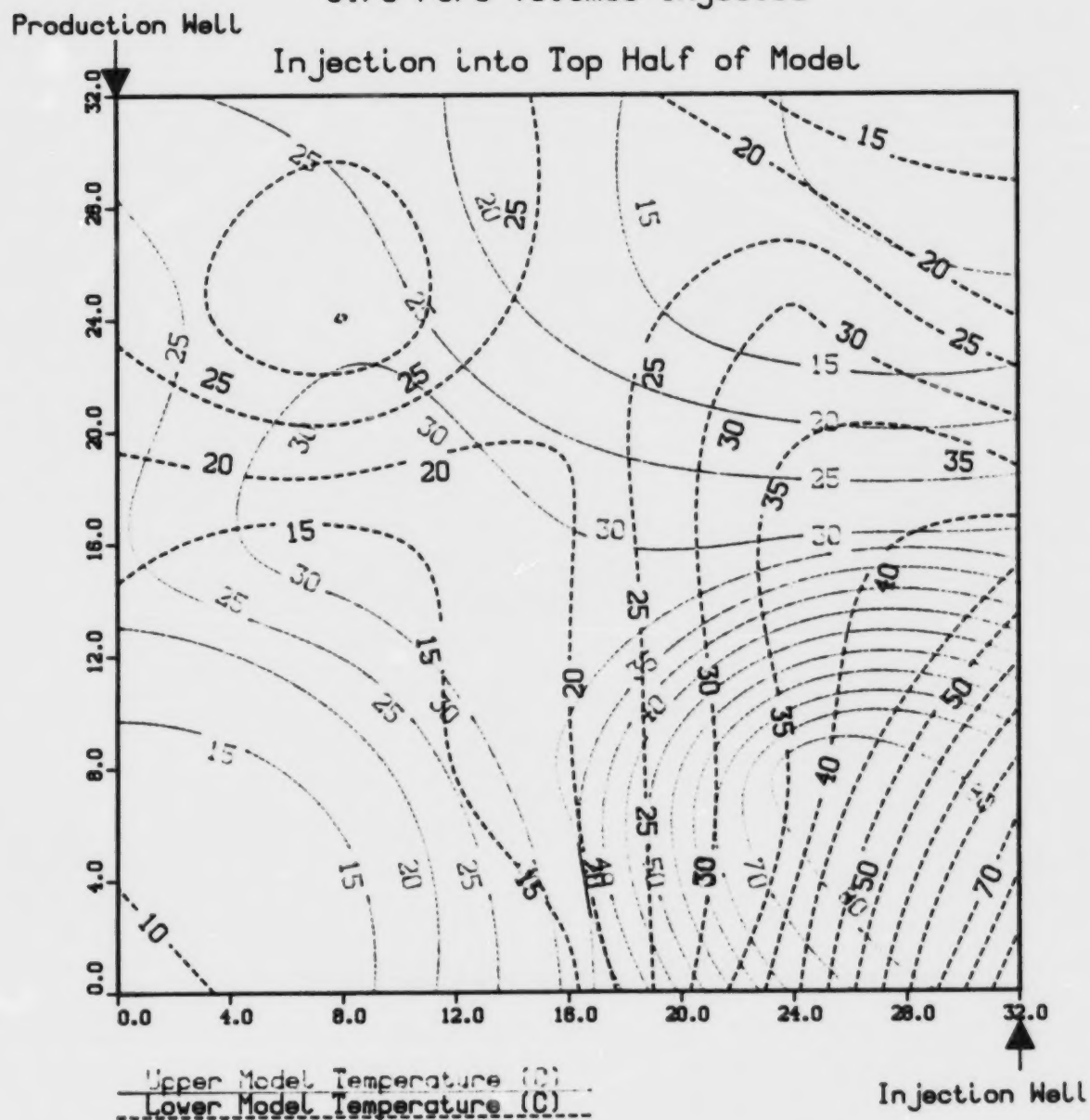
Temperature Profile for
0.75 Pore Volumes Injected

Figure 8.15

Run 29: Gas Inj.-Steamflood of Model

Temperature Profile for
1.00 Pore Volumes Injected

Production Well

Injection into Top Half of Model

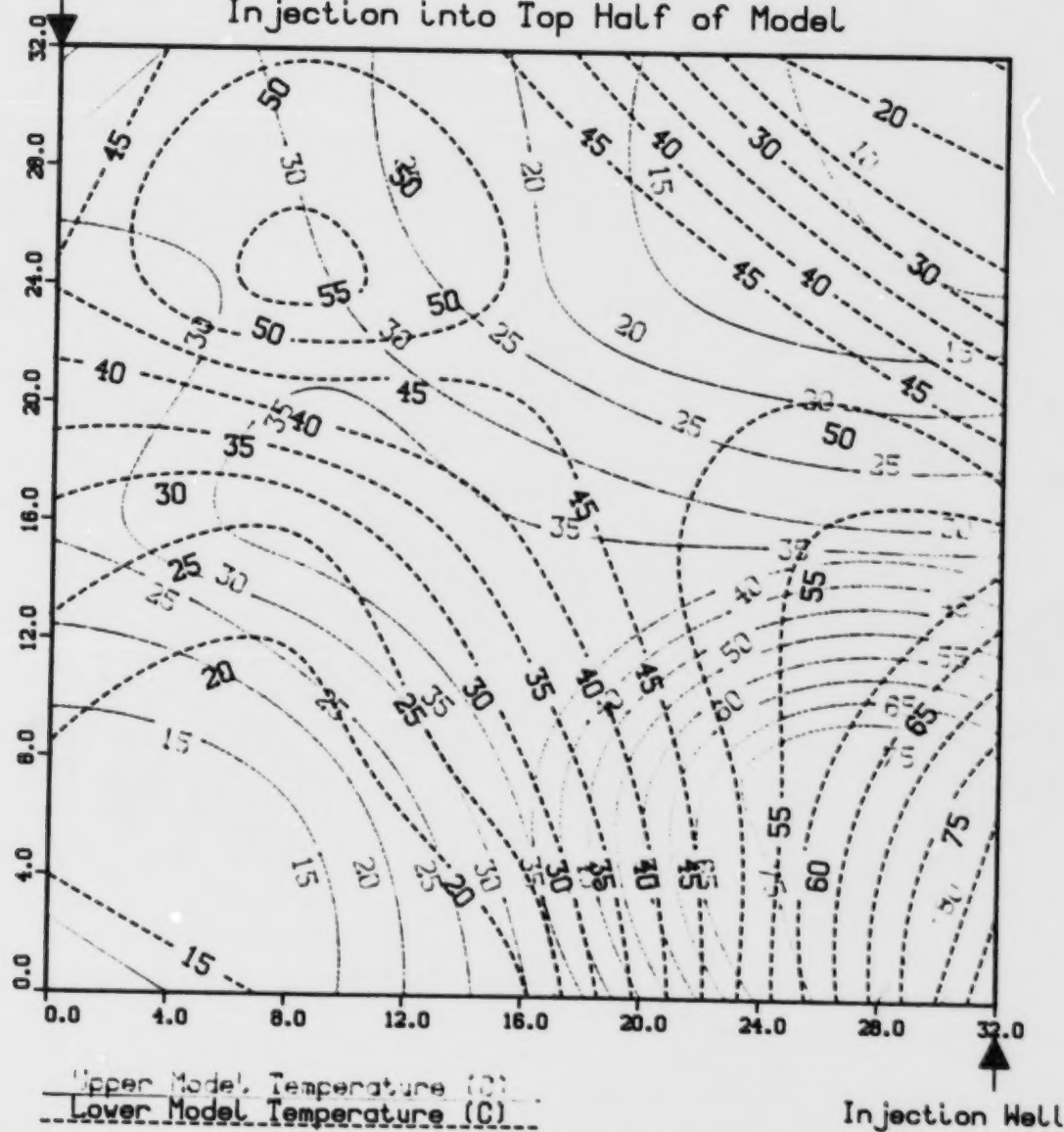


Figure 8.16

Run 29: Gas Inj.-Steamflood of Model

Temperature Profile for
1.25 Pore Volumes Injected

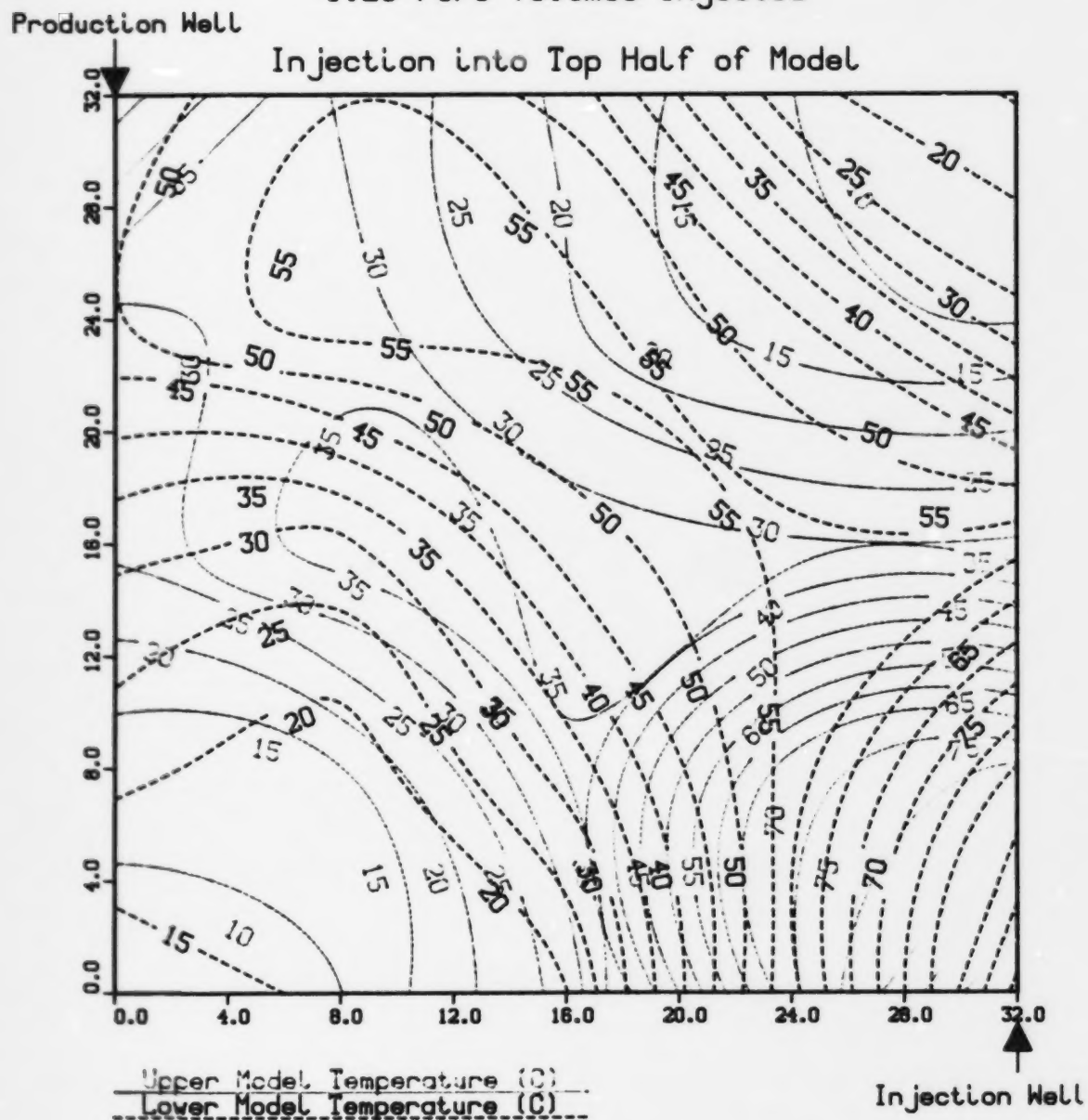


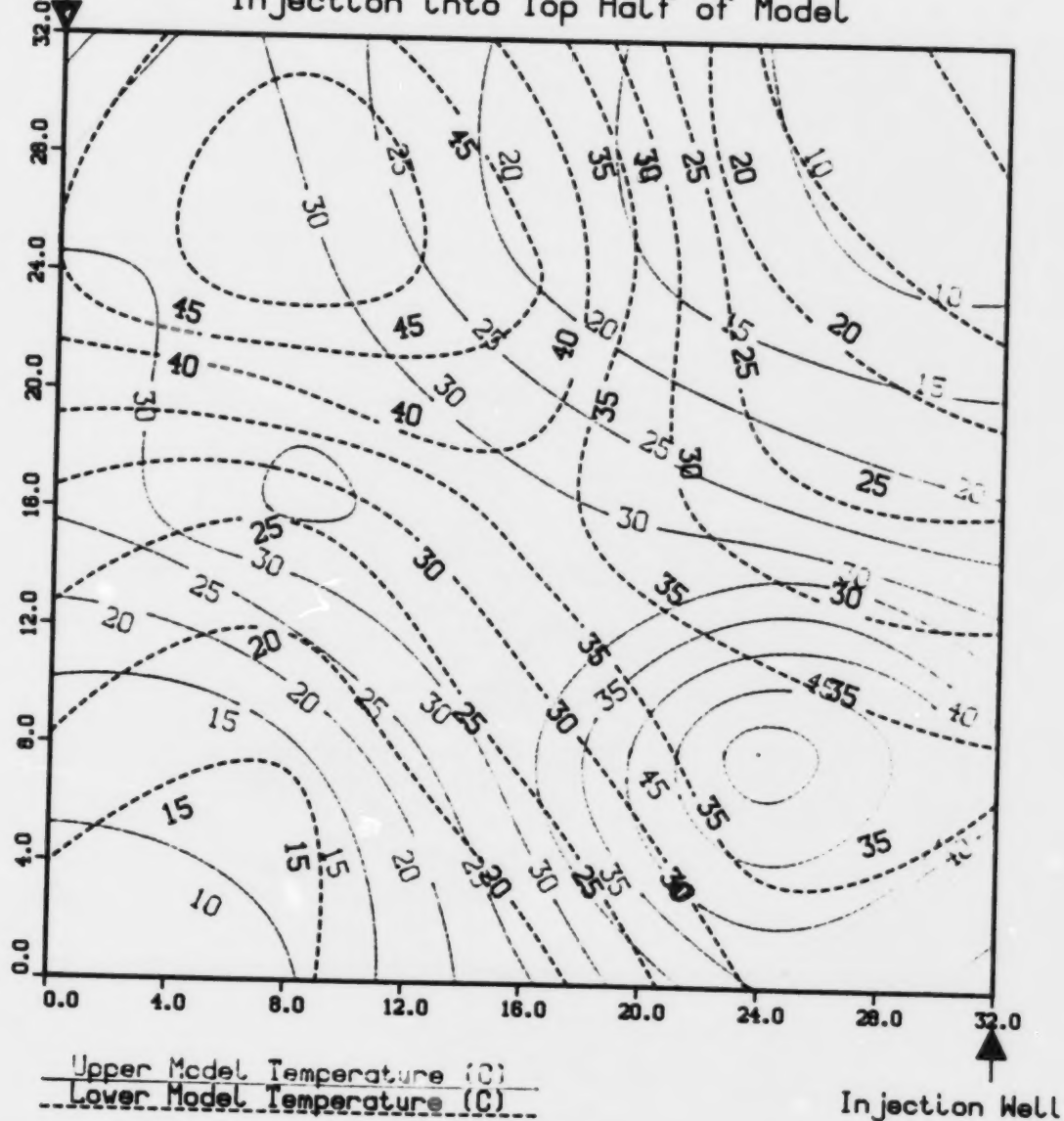
Figure 8.17

Run 29: Gas Inj.-Steamflood of Model

Temperature Profile for
1.50 Pore Volumes Injected

Production Well

Injection into Top Half of Model



However, at later times, it can be observed that the lower portion of the model is warmer, particularly near the production end.

Figure 8.18 compares the production response for continuous steam injection and steam injection following gas injection in a homogeneous model. It can be seen that the production response of the gas injection process is slightly lower than that of the continuous steam injection process. However, in a reservoir where steam injectivity is a problem, the injectivity improvement obtained by gas injection may justify the small decrease in oil recovery.

Gas Injection Experiments--Bottom Water Models

Steam injected into reservoirs underlain by bottom water often channels directly into the bottom water zone, thus drastically reducing the effectiveness of the steamflooding process. As mentioned previously, it was hypothesized that by injecting an inert gas prior to steam injection, a flow channel away from the bottom water will be created for the steam, thus reducing the often detrimental effect of the bottom water. Three gas injection experiments were conducted in bottom water models to test this hypothesis.

Run 30 was a gas injection experiments conducted in a bottom water model. Gas was injected at 15 kPa (2 psia) into the upper portion of the model until the instantaneous oil production was negligible, which occurred after three minutes (approximately 0.3 prototype years). The model was then steamflooded, with the production well open over the entire model thickness.

Table 8.13 lists the experimental parameters for this run and details the production performance. It can be seen that after 2.23 pore volumes of steam had been injected, 26.2% of the original oil in place had been recovered. Figures 8.19 through 8.22 show the temperature profiles within the model for the injection 0.5, 1.0, 1.5, and 2.0 pore volumes of steam, respectively.

Figure 8.18 Recovery Comparison for Runs 10 & 29

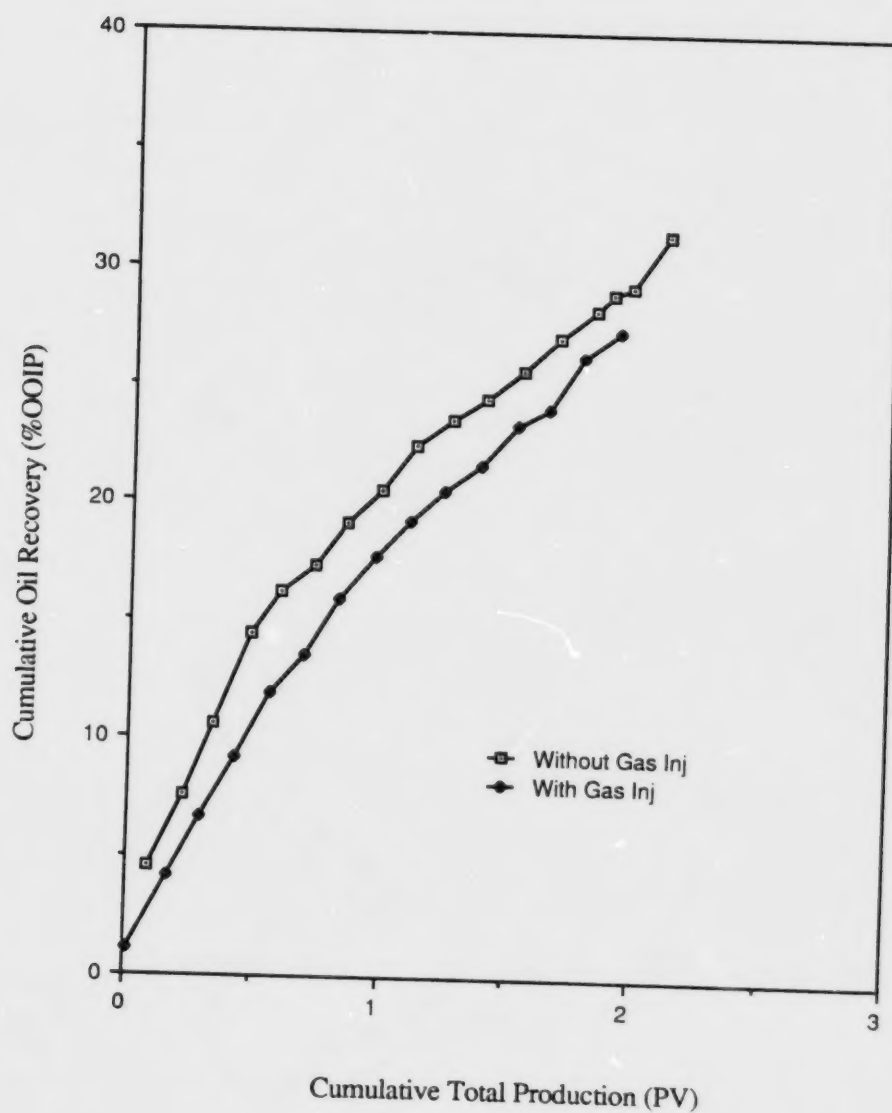


Table 8.13 : Experimental Data For Run 30
Model Simulating the Aberfeldy Reservoir--Continuous Steamflood Following Gas Injection In Bottom Water Model
 Injection and Production From Upper Portion of Model

Pore Volume of Bead Pack: 15160.0 cc
 Porosity of Bead Pack: 36.09 %
 Hydrocarbon Pore Volume: 11515.0 cc
 Initial Oil Saturation: 75.96 %
 Irreducible Water Saturation: 24.04 %
 Initial Model Temperature: 3.0 C
 Water Feed Flow Rate: 199.3 cc
 Steam Feed Flow Rate: 30.1 cc
 Total Steam Injection Rate: 229.4 cc
 Bottom Water % of Total Thick: 15.2 %
 Gas Cap Volume: 140.0 cc

Sample	Sample Volume (cc)	Water Volume (cc)	Total Cumulative Production (cc)	Total Cumulative Production (PV)	Cumulative Oil Produced (cc)	(%o.oip)	Water in Sample(%)	Oil in Sample (%)	Inst. OSR	Cum. OSR
1	1280.0	1240.0	1280.0	0.0844	40.0	0.35%	96.88%	3.13%	0.0313	0.0313
2	2010.0	1950.0	3290.0	0.2170	100.0	0.87%	97.01%	2.99%	0.0299	0.0304
3	1960.0	1870.0	5250.0	0.3463	190.0	1.65%	95.41%	4.59%	0.0459	0.0362
4	1880.0	1765.0	7130.0	0.4703	305.0	2.65%	93.88%	6.12%	0.0612	0.0428
5	1920.0	1750.0	9050.0	0.5970	475.0	4.13%	91.15%	8.85%	0.0885	0.0525
6	1990.0	1795.0	11040.0	0.7282	670.0	5.82%	90.20%	9.80%	0.0980	0.0607
7	1895.0	1650.0	12935.0	0.8532	915.0	7.95%	87.07%	12.93%	0.1293	0.0707
8	2040.0	1820.0	14975.0	0.9878	1135.0	9.86%	89.22%	10.78%	0.1078	0.0758
9	1800.0	1600.0	16775.0	1.1065	1335.0	11.59%	88.89%	11.11%	0.1111	0.0796
10	1980.0	1730.0	18755.0	1.2371	1585.0	13.76%	87.37%	12.63%	0.1263	0.0845
11	1900.0	1680.0	20655.0	1.3625	1805.0	15.68%	88.42%	11.58%	0.1158	0.0874
12	1950.0	1740.0	22605.0	1.4911	2015.0	17.50%	89.23%	10.77%	0.1077	0.0891
13	1840.0	1630.0	24445.0	1.6125	2225.0	19.32%	88.59%	11.41%	0.1141	0.0910
14	1940.0	1745.0	26385.0	1.7404	2420.0	21.02%	89.95%	10.05%	0.1005	0.0917
15	1765.0	1600.0	28150.0	1.8569	2585.0	22.45%	90.65%	9.35%	0.0935	0.0918
16	1930.0	1760.0	30080.0	1.9842	2755.0	23.93%	91.19%	8.81%	0.0881	0.0916
17	1790.0	1655.0	31870.0	2.1022	2890.0	25.10%	92.46%	7.54%	0.0754	0.0907
18	1930.0	1805.0	33800.0	2.2296	3015.0	26.18%	93.52%	6.48%	0.0648	0.0892

Figure 8.19

Run 30: Gas Inj in Bottom Water Model

Temperature Profile for
0.50 Pore Volumes Injected

Production Well

Injection into Top Half of Model

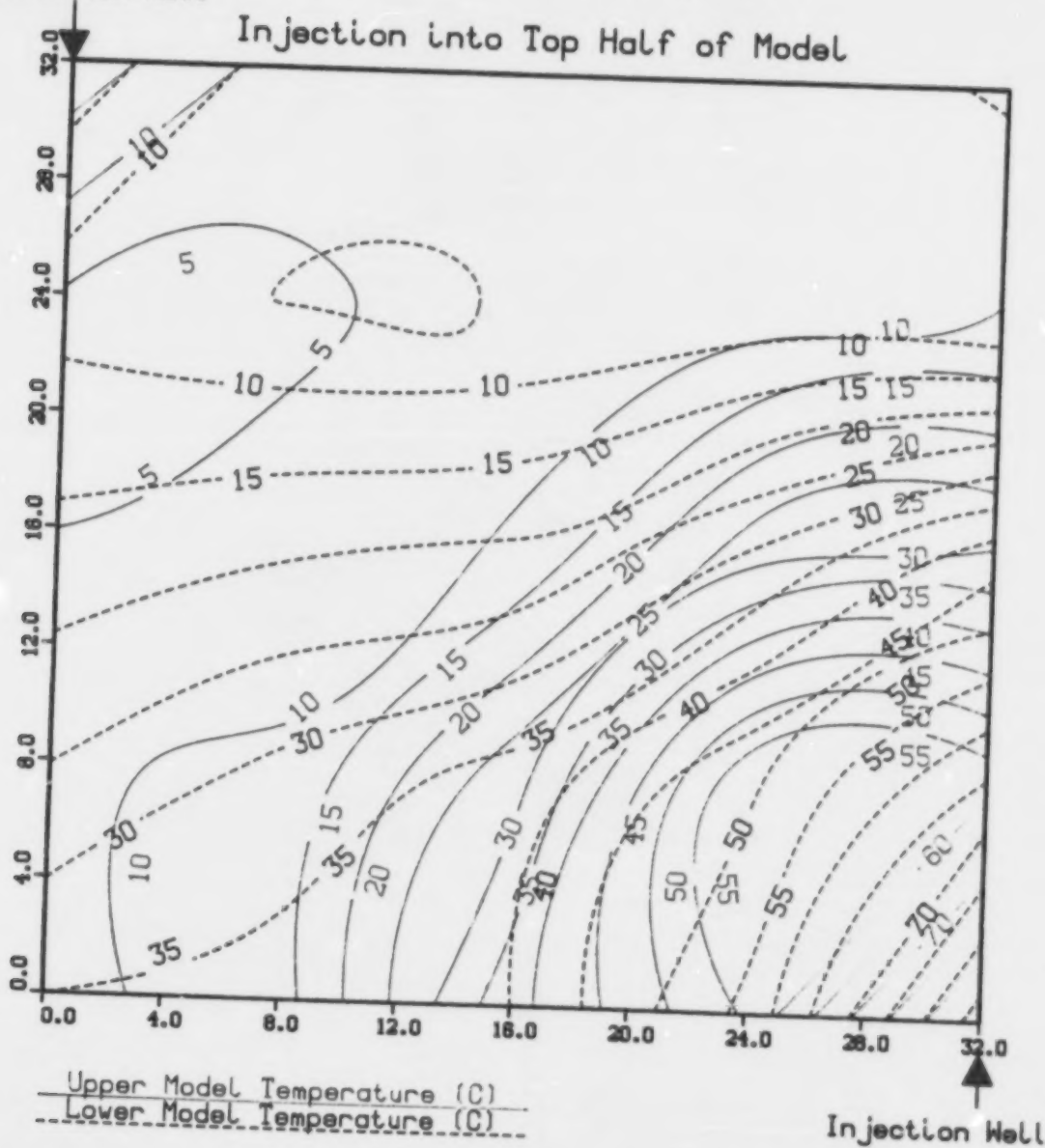


Figure 8.20

Run 30: Gas Inj in Bottom Water Model

Temperature Profile for
1.00 Pore Volumes Injected

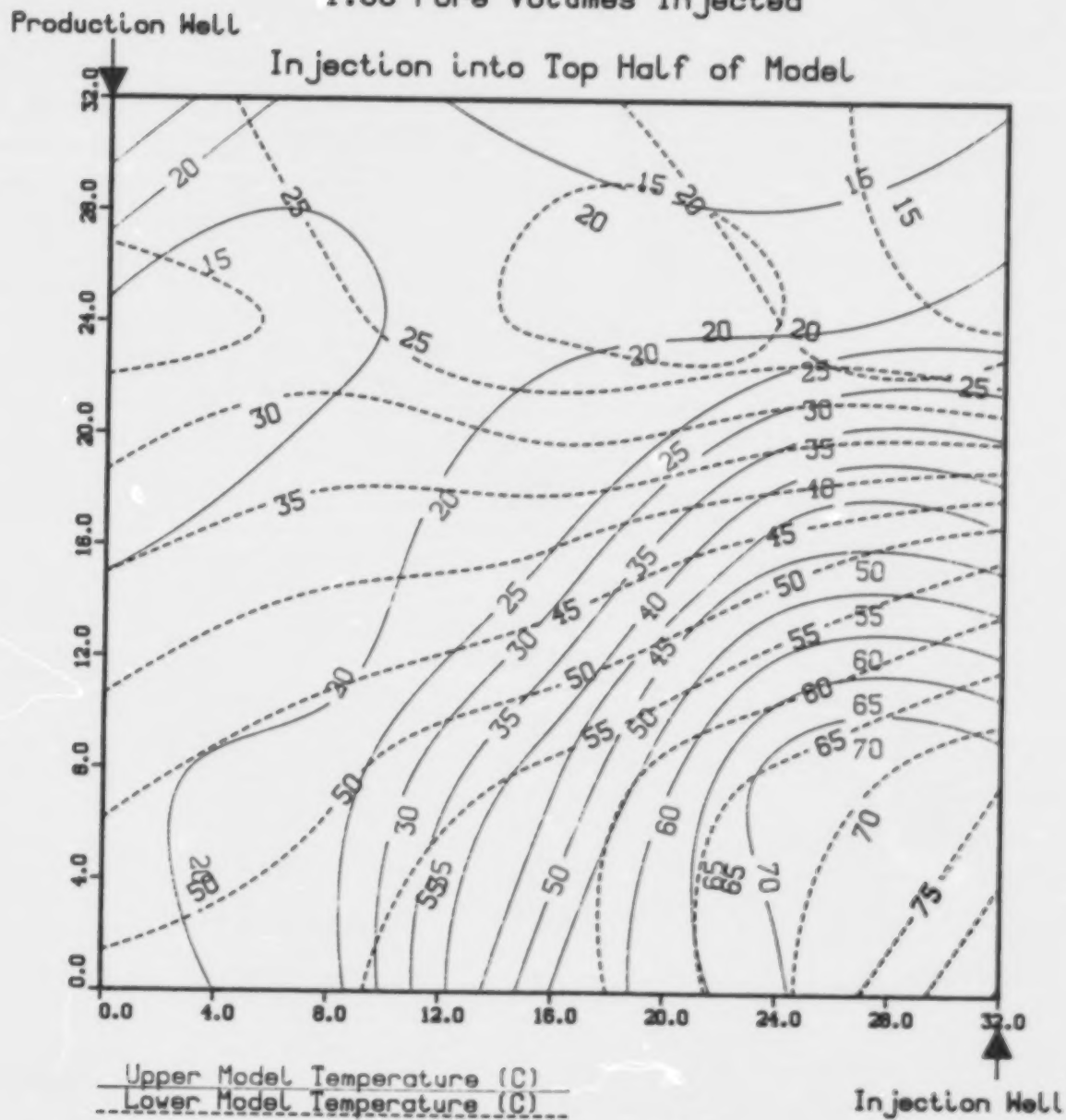


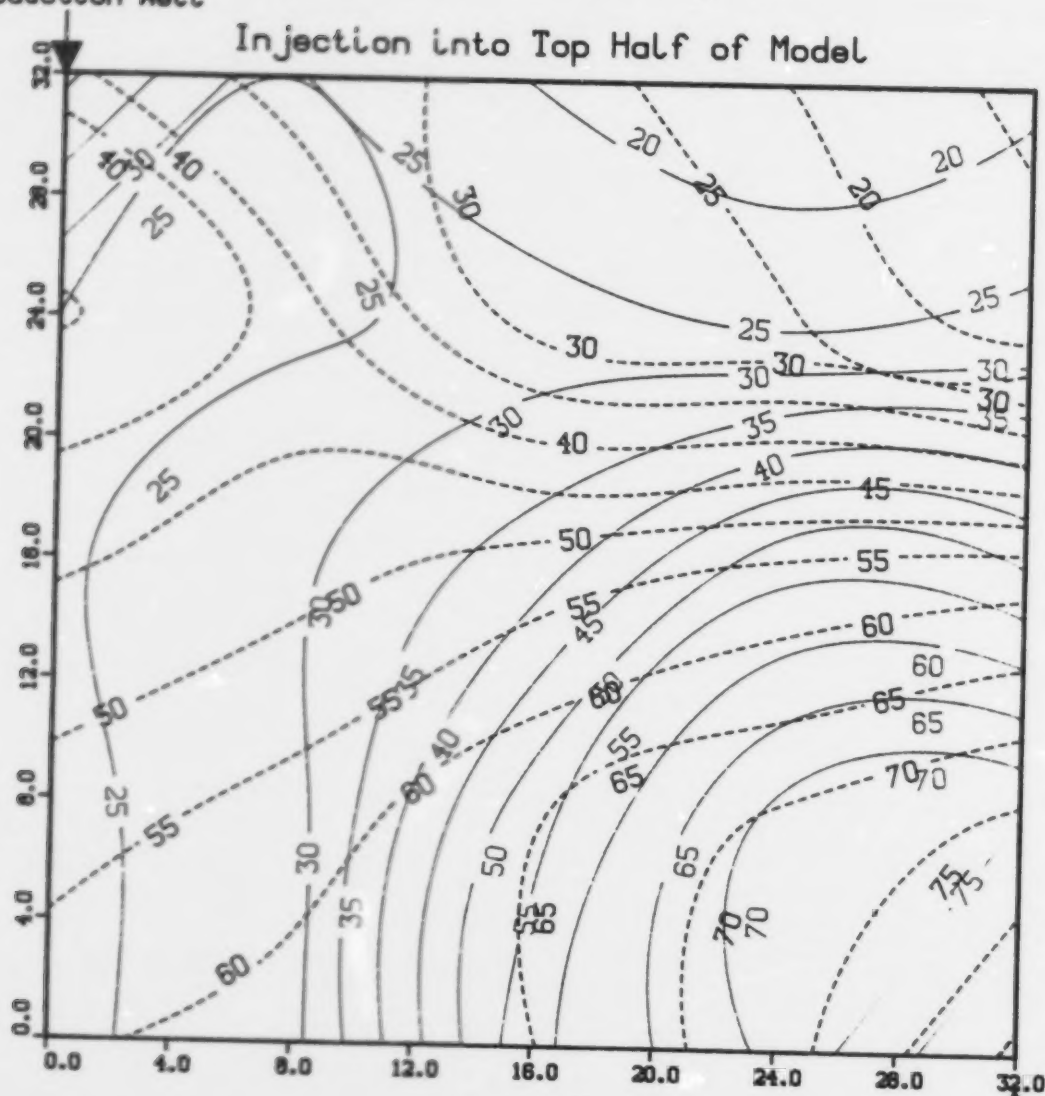
Figure 8.21

Run 30: Gas Inj in Bottom Water Model

Temperature Profile for
1.50 Pore Volumes Injected

Production Well

Injection into Top Half of Model



Upper Model Temperature (C)

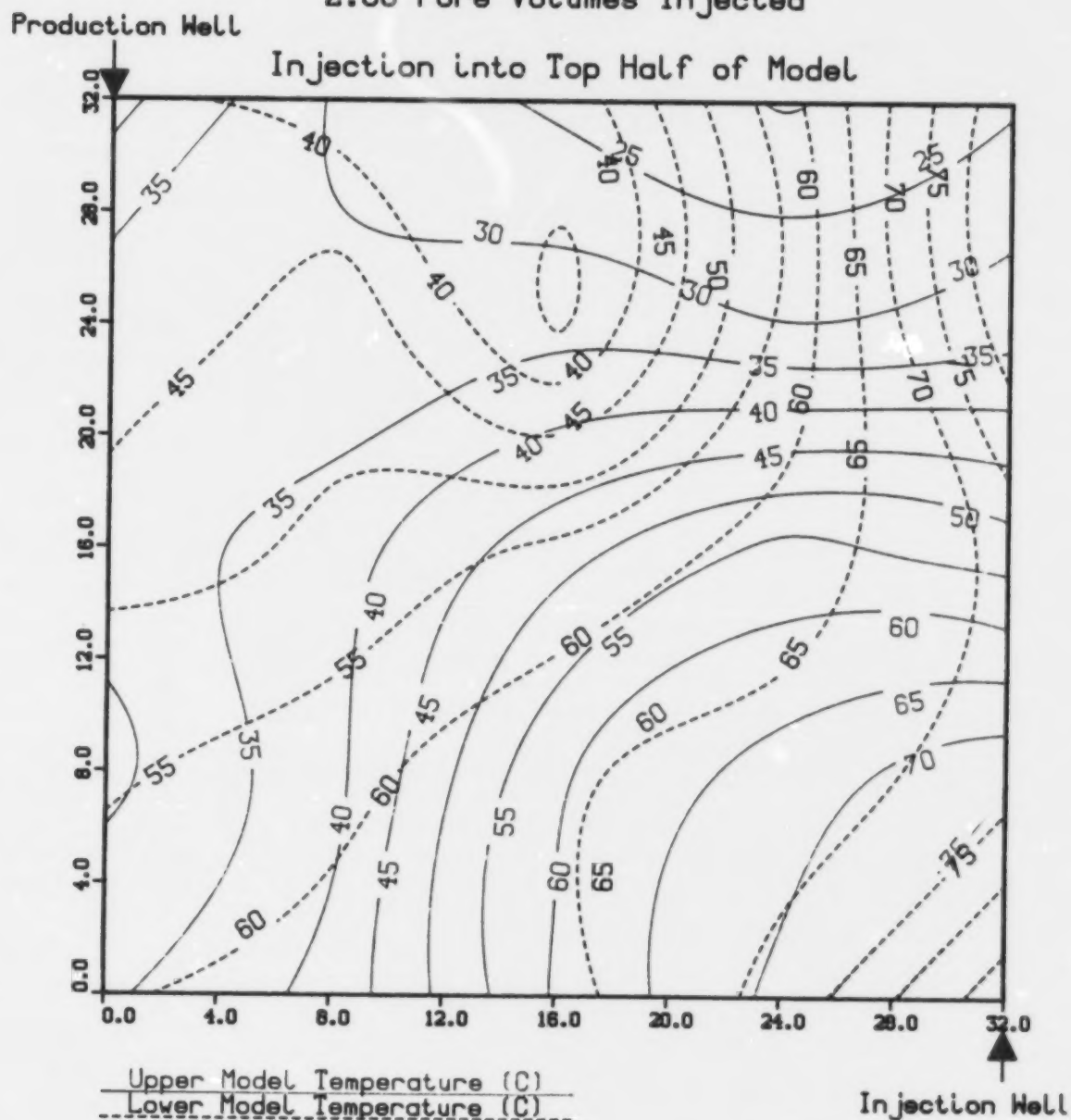
Lower Model Temperature (C)

Injection Well

Figure 8.22

Run 30: Gas Inj in Bottom Water Model

Temperature Profile for
2.00 Pore Volumes Injected



Run 37 was a gas injection--steamflood experiment conducted in a bottom water model. Gas was injected at 15 kPa (2 psia) for three minutes, then steam was injected when it attained the desired temperature. Table 8.14 presents the experimental details of this run and lists the oil recovery as a function of steam injection. It can be seen that the final recovery was 20.94% after 1.98 pore volumes of steam were injected. The steam was injected into the upper part of the formation but the production well was open over the entire model thickness. Figures 8.23 through 8.28 show the temperature profiles for the experiments after 0.25, 0.50, 0.75, 1.00, 1.25, and 1.50 pore volumes of steam have been injected, respectively. These reveal that by having the production open over the entire formation, including the bottom water, the highly mobile bottom water is readily produced, thus reducing the oil production. It was felt that confining the production to the upper part of the model would help to exclude the bottom water from the production well and this was done in the next experiment.

Run 38 was another experiment conducted on a bottom water model which involved injecting a small amount of gas into the model prior to steamflooding. The bottom water layer was the largest that has been achieved in all of the bottom water experiments, being 3056cc or 19.7% of the total model pore volume. The increased thickness is attributed to lowering the temperature of the refrigerator while freezing the bottom water in the model.

Gas was injected at 15 kPa (2 psia) for 6 minutes and the injected gas had the effect of creating a small gas cap of 80cc or 0.5% of the model pore volume. The experimental parameters and the production results for this experiment are presented in Table 8.15 where it can be seen that the final oil recovery was 20.66% ooip after injecting 1.83 pore volumes of steam.

Figures 8.29 and 8.30 give temperature profiles for an injector to producer cross-section for a gas injection steamflood experiment (Run 38) and a straight steamflood experiment (Run 39), respectively, at 0.25 pore volumes of steam injected. Figures 8.31

Table 8.14 : Experimental Data For Run 37
Model Simulating the Aberfeldy Reservoir--Gas Injection Prior to Steamflood in Bottom Water Model
 Injection into top half of model; Production over entire interval.

Pore Volume of Bead Pack: 15150.0 cc
 Porosity of Bead Pack: 36.07 %
 Hydrocarbon Pore Volume: 12915.0 cc
 Initial Oil Saturation: 85.25 %
 Irreducible Water Saturation: 14.75 %
 Initial Model Temperature: 3.0 C
 Water Feed Flow Rate: 199.7 cc
 Steam Feed Flow Rate: 30.4 cc
 Total Steam Injection Rate: 230.1 cc
 Vol. of Bottom Water in Mode: 1690.4 cc
 Bottom Water Thickness: 11.16 % of Total Thickness
 Gas Cap Volume: ?

Sample	Sample Volume (cc)	Water Volume (cc)	Total Cumulative Production (cc)	Total Cumulative Production (PV)	Cumulative Oil Produced (cc)	(%o.oip)	Water in Sample(%)	Oil in Sample (%)	Inst. OSR	Cum. OSR
1	820.0	760.0	820.0	0.0541	60.0	0.46%	92.68%	7.32%	0.0732	0.0732
2	1820.0	1590.0	2640.0	0.1743	290.0	2.25%	87.36%	12.64%	0.1264	0.1098
3	1890.0	1730.0	4530.0	0.2990	450.0	3.48%	91.53%	8.47%	0.0847	0.0993
4	1970.0	1730.0	6500.0	0.4290	690.0	5.34%	87.82%	12.18%	0.1218	0.1062
5	1860.0	1640.0	8360.0	0.5518	910.0	7.05%	88.17%	11.83%	0.1183	0.1089
6	2000.0	1730.0	10360.0	0.6838	1180.0	9.14%	86.50%	13.50%	0.1350	0.1139
7	1850.0	1620.0	12210.0	0.8059	1410.0	10.92%	87.57%	12.43%	0.1243	0.1155
8	2125.0	1890.0	14335.0	0.9462	1645.0	12.74%	88.94%	11.06%	0.1106	0.1148
9	1880.0	1695.0	16215.0	1.0703	1830.0	14.17%	90.16%	9.84%	0.0984	0.1129
10	1950.0	1775.0	18165.0	1.1990	2005.0	15.52%	91.03%	8.97%	0.0897	0.1104
11	1950.0	1800.0	20115.0	1.3277	2155.0	16.69%	92.31%	7.69%	0.0769	0.1071
12	1950.0	1810.0	22065.0	1.4564	2295.0	17.77%	92.82%	7.18%	0.0718	0.1040
13	1880.0	1770.0	23945.0	1.5805	2405.0	18.62%	94.15%	5.85%	0.0585	0.1004
14	1940.0	1840.0	25885.0	1.7086	2505.0	19.40%	94.85%	5.15%	0.0515	0.0968
15	2020.0	1910.0	27905.0	1.8419	2615.0	20.25%	94.55%	5.45%	0.0545	0.0937
16	2100.0	2010.0	30005.0	1.9805	2705.0	20.94%	95.71%	4.29%	0.0429	0.0902

Figure 8.23

Run 37: Gas Inj & SF In Bottom Water

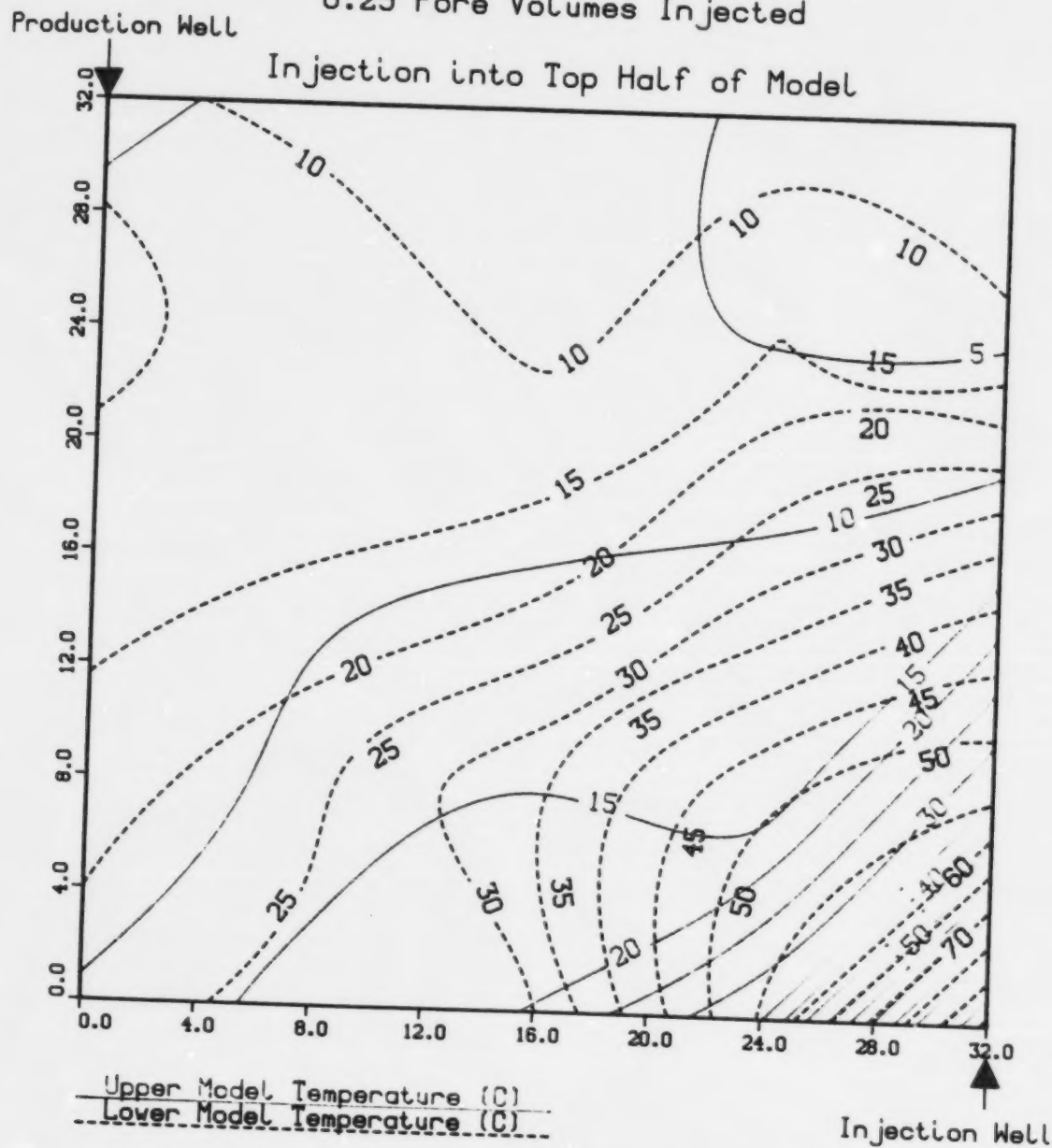
Temperature Profile for
0.25 Pore Volumes Injected

Figure 8.24

Run 37: Gas Inj & SF In Bottom Water

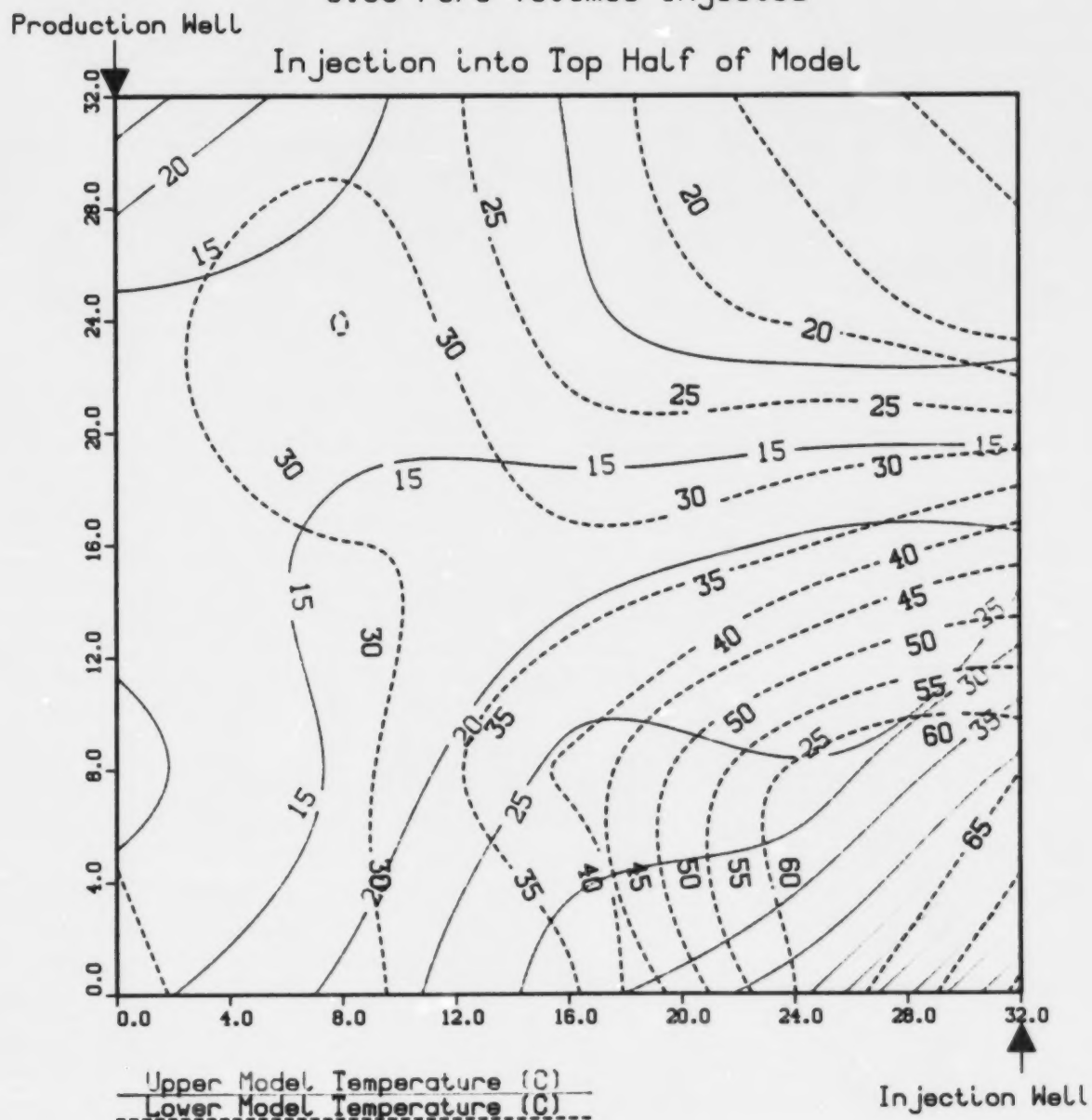
Temperature Profile for
0.50 Pore Volumes Injected

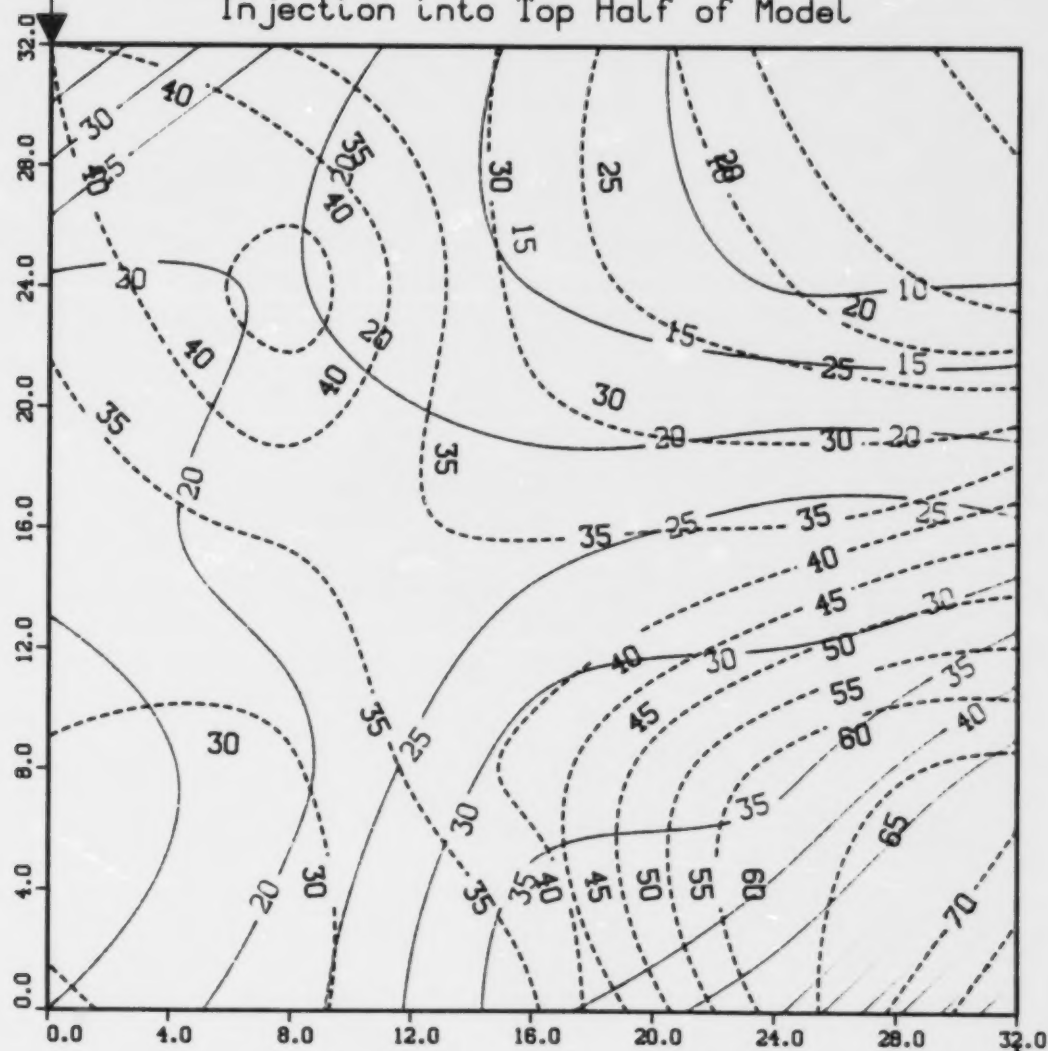
Figure 8.25

Run 37: Gas Inj & SF In Bottom Water

Temperature Profile for
0.75 Pore Volumes Injected

Production Well

Injection into Top Half of Model



Upper Model Temperature (C)

Lower Model Temperature (C)

Injection Well

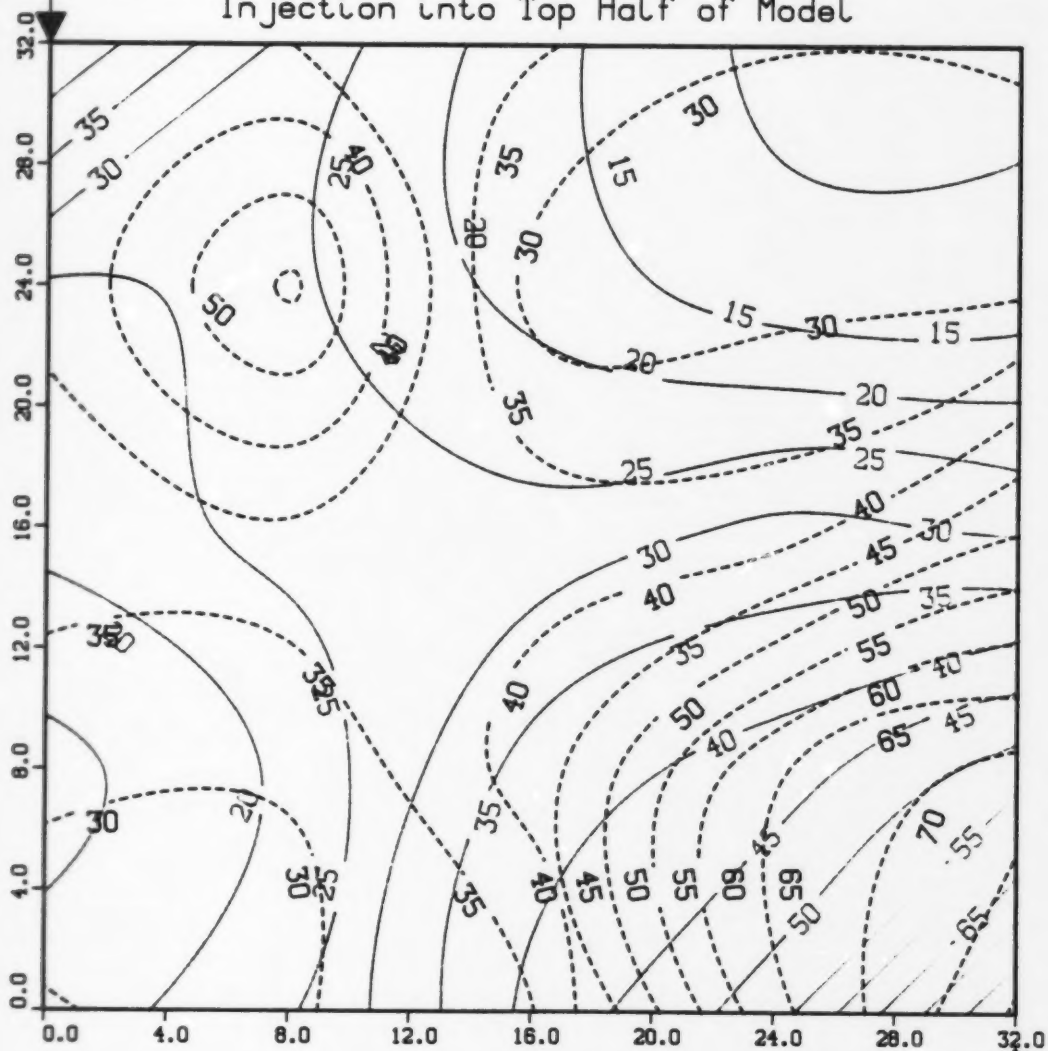
Figure 8.26

Run 37: Gas Inj & SF In Bottom Water

Temperature Profile for
1.00 Pore Volumes Injected

Production Well

Injection into Top Half of Model



Upper Model Temperature (C)
Lower Model Temperature (C)

Injection Well

Figure 8.27

Run 37: Gas Inj & SF In Bottom Water

Temperature Profile for
1.25 Pore Volumes Injected

Production Well

Injection into Top Half of Model

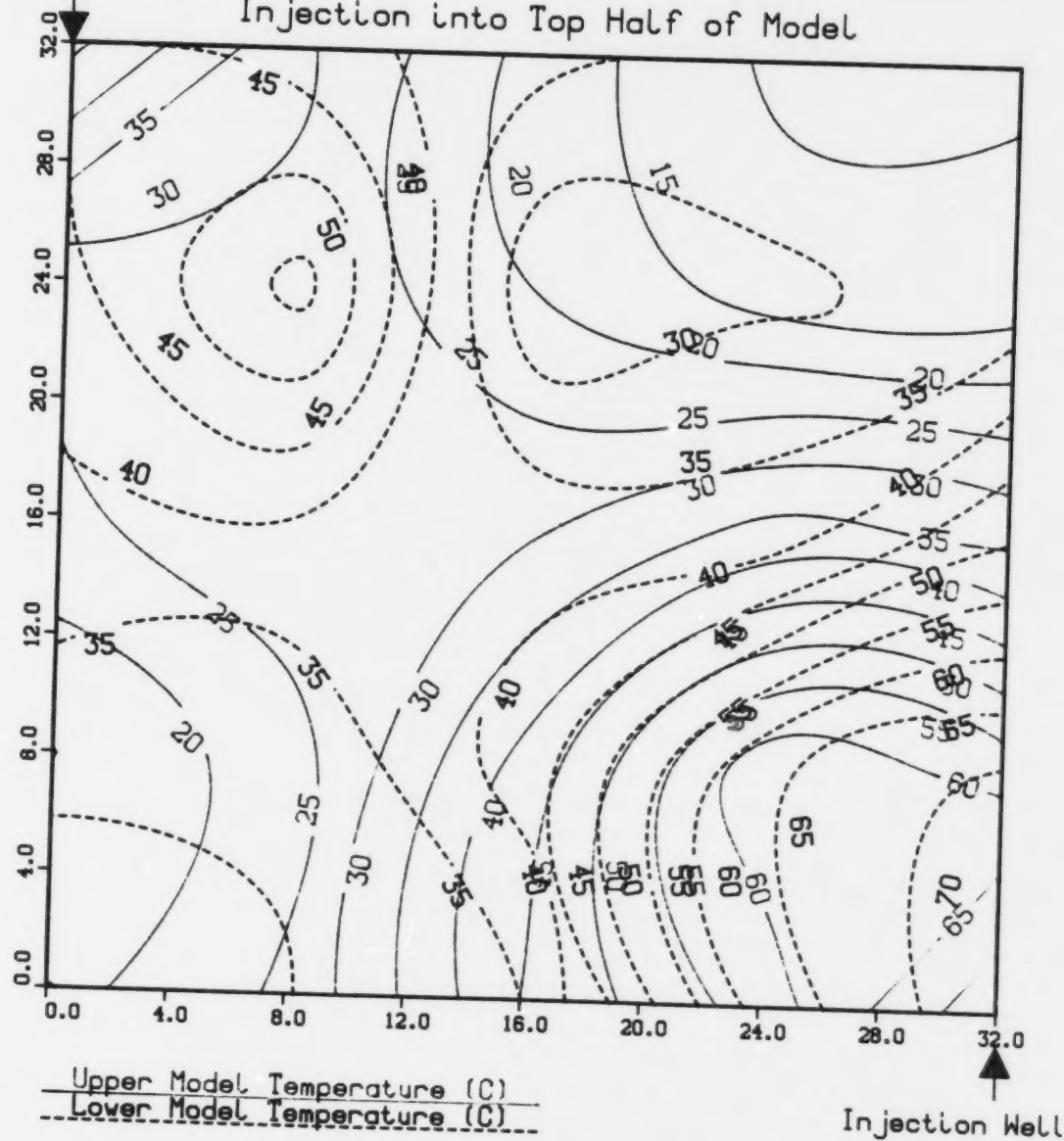


Figure 8.28

Run 37: Gas Inj & SF In Bottom Water

Temperature Profile for
1.50 Pore Volumes Injected

Production Well

Injection into Top Half of Model

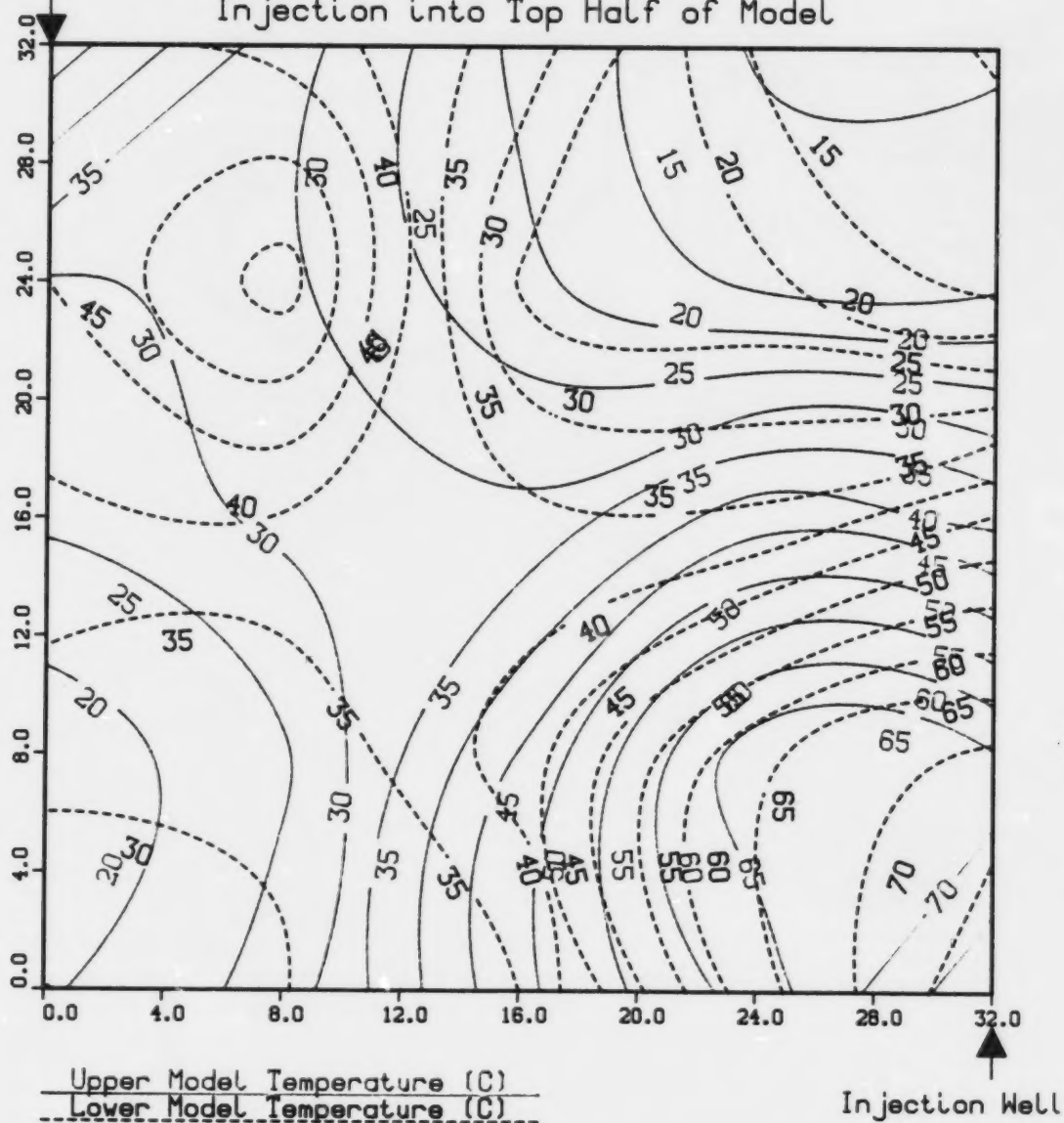


Table 8.15 : Experimental Data For Run 38
Model Simulating the Aberfeldy Reservoir--Gas Injection Prior to Steamflood in Bottom Water Model
Injection over entire well; Production from top half of model.

Pore Volume of Bead Pack: 15505.0 cc
Porosity of Bead Pack: 36.91 %
Hydrocarbon Pore Volume: 13165.0 cc
Initial Oil Saturation: 84.91 %
Irreducible Water Saturation: 15.09 %
Initial Model Temperature: 3.0 C
Water Feed Flow Rate: 199.7 cc
Steam Feed Flow Rate: 30.4 cc
Total Steam Injection Rate: 230.1 cc
Vol. of Bottom Water in Model: 3056.0 cc
Bottom Water Thickness: 19.71 % of Total Thickness
Gas Cap Volume: 80.00 cc

Sample	Sample Volume (cc)	Water Volume (cc)	Total Cumulative Production (cc)	Total Cumulative Production (PV)	Cumulative Oil Produced (cc)	Cumulative Oil Produced (%ooinp)	Water in Sample (%)	Oil in Sample (%)	Inst. OSR	Cum. OSR
1	80.0	0.0	80.0	0.0052	80.0	0.61%	0.00%	100.00%	1.0000	1.0000
2	1980.0	1785.0	2060.0	0.1329	275.0	2.09%	90.15%	9.85%	0.0985	0.1335
3	1885.0	1635.0	3945.0	0.2544	525.0	3.99%	86.74%	13.26%	0.1326	0.1331
4	1935.0	1690.0	5880.0	0.3792	770.0	5.85%	87.34%	12.66%	0.1266	0.1310
5	2000.0	1700.0	7880.0	0.5082	1070.0	8.13%	85.00%	15.00%	0.1500	0.1358
6	2200.0	1970.0	10080.0	0.6501	1300.0	9.87%	89.55%	10.45%	0.1045	0.1290
7	2100.0	1890.0	12180.0	0.7856	1510.0	11.47%	90.00%	10.00%	0.1000	0.1240
8	2020.0	1820.0	14200.0	0.9158	1710.0	12.99%	90.10%	9.90%	0.0990	0.1204
9	1945.0	1755.0	16145.0	1.0413	1900.0	14.43%	90.23%	9.77%	0.0977	0.1177
10	2080.0	1900.0	18225.0	1.1754	2080.0	15.80%	91.35%	8.65%	0.0865	0.1141
11	1970.0	1820.0	20195.0	1.3025	2230.0	16.94%	92.39%	7.61%	0.0761	0.1104
12	1990.0	1865.0	22185.0	1.4308	2355.0	17.89%	93.72%	6.28%	0.0628	0.1062
13	2010.0	1880.0	24195.0	1.5605	2485.0	18.88%	93.53%	6.47%	0.0647	0.1027
14	2045.0	1915.0	26240.0	1.6924	2615.0	19.86%	93.64%	6.36%	0.0636	0.0997
15	2075.0	1970.0	28315.0	1.8262	2720.0	20.66%	94.94%	5.06%	0.0506	0.0961

Figure 8.29 Temp Profile For Run 38
Injector to Producer Cross-Section
 0.25 Pore Volumes of Steam Injected.

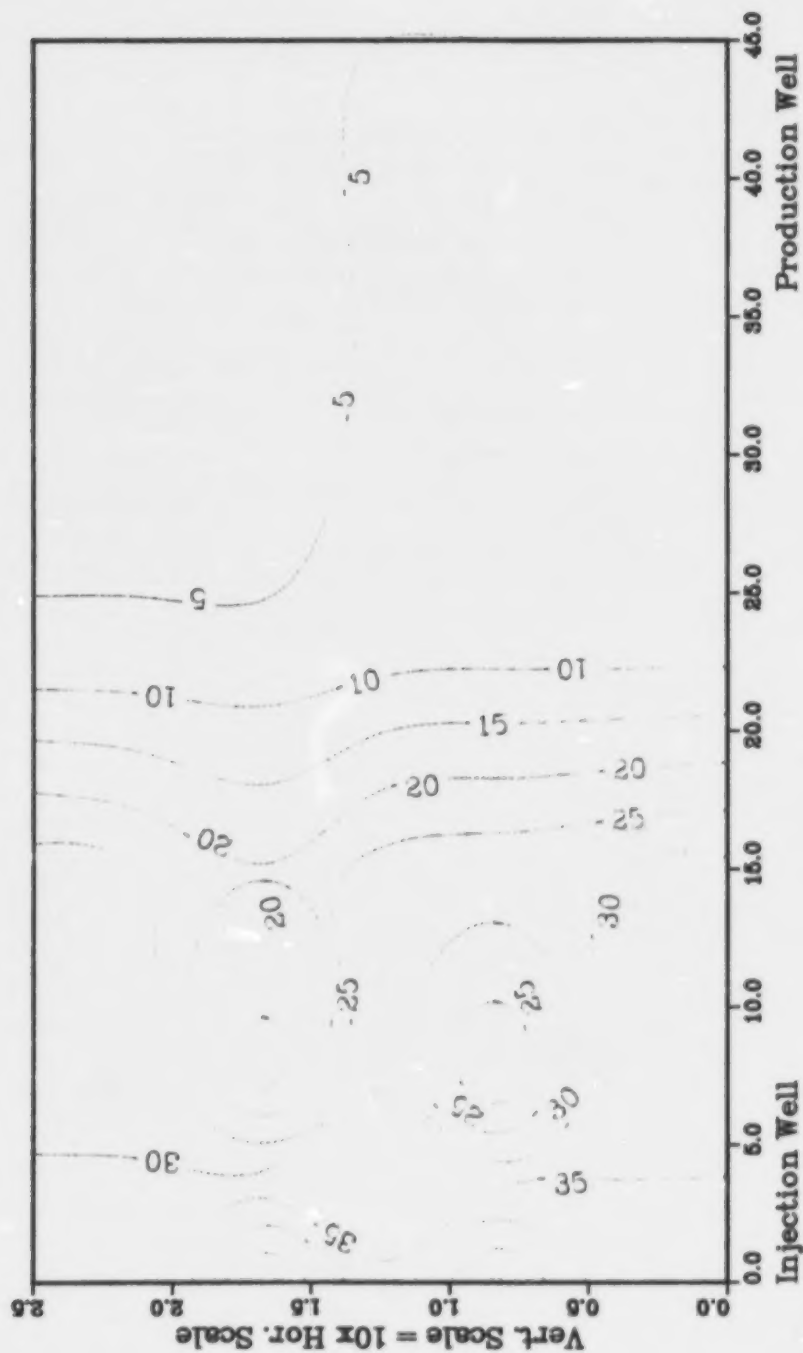


Figure 8.30 Temp Profile For Run 39
Injector to Producer Cross-Section
 0.25 Pore Volumes of Steam Injected.

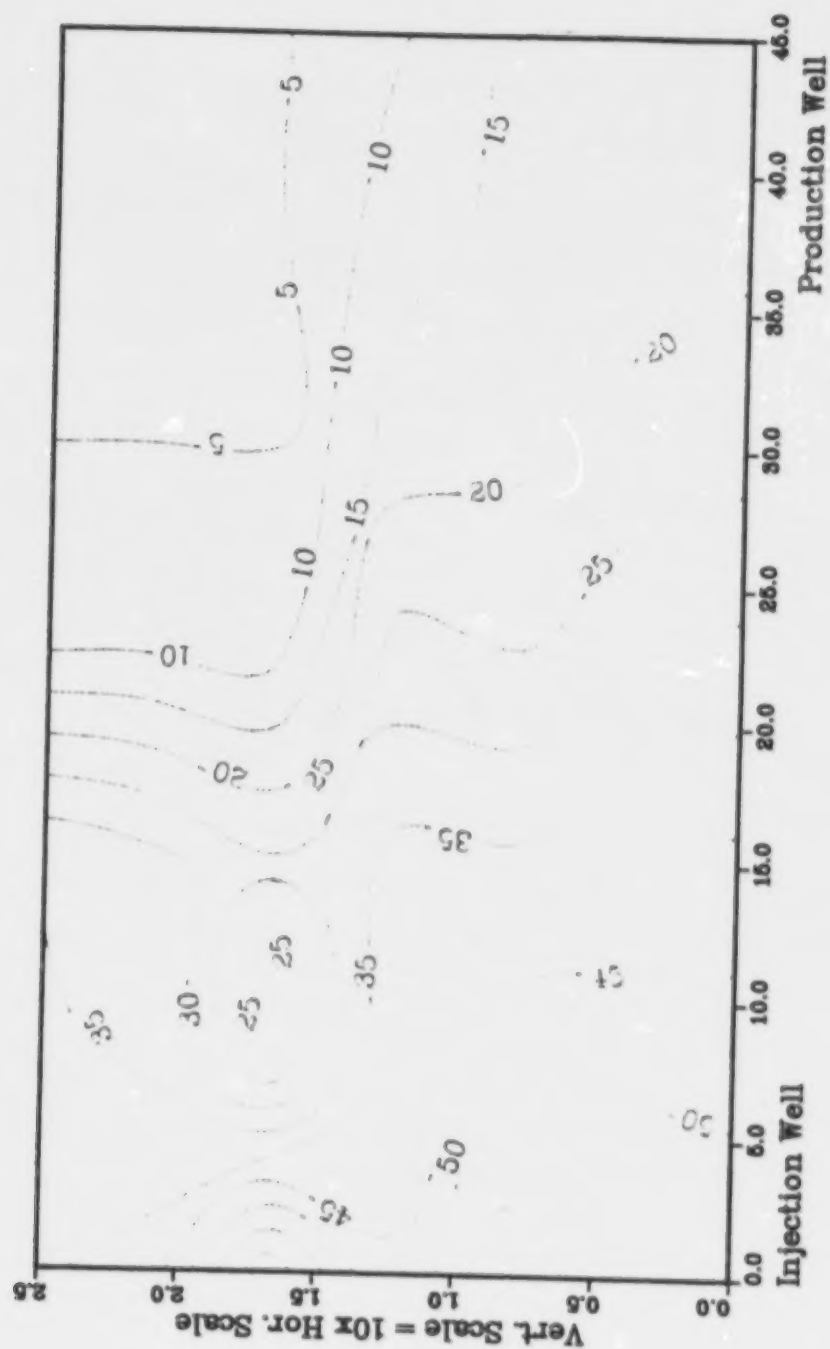
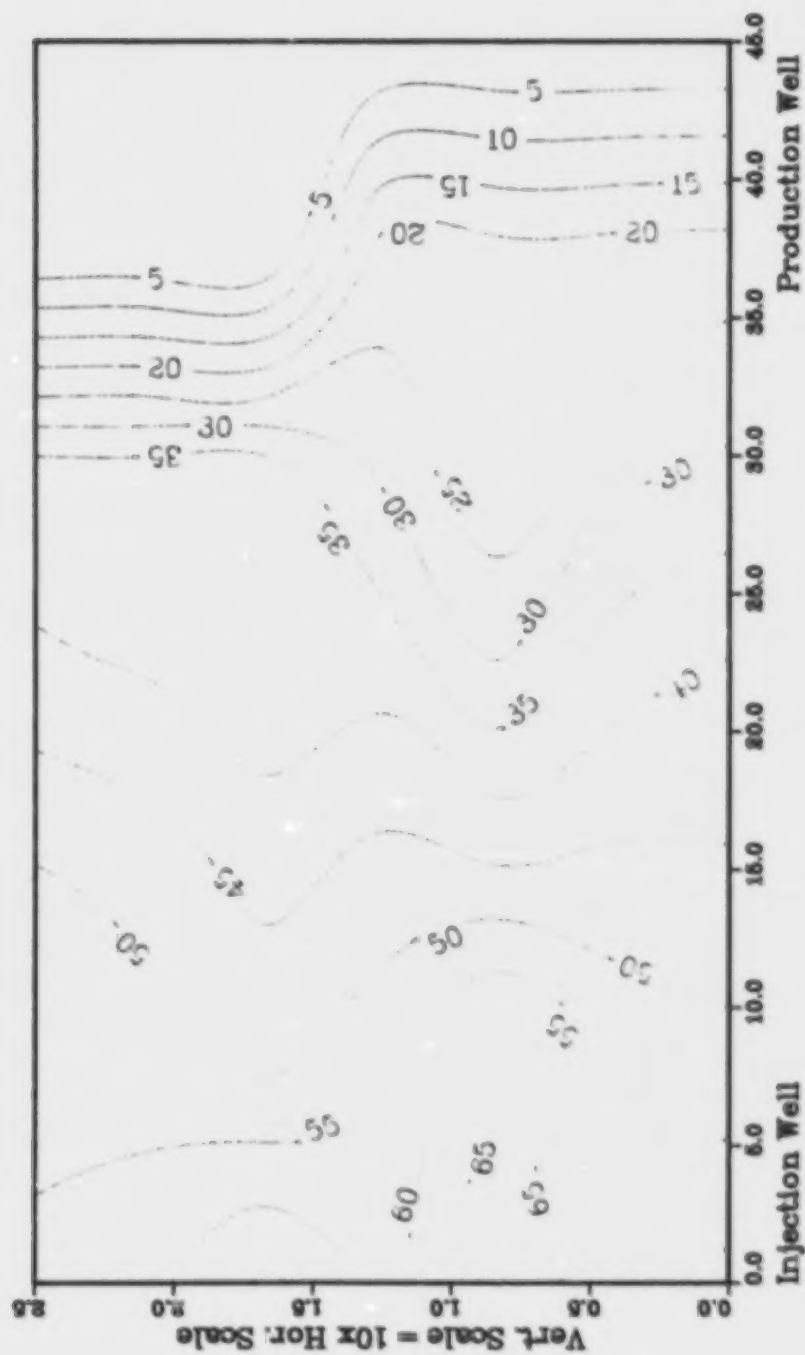


Figure 8.31 Temp Profile For Run 38
Injector to Producer Cross-Section
 1.50 Pore Volumes of Steam Injected.



and 8.32 give temperature profiles for Runs 38 and 39, respectively, at 1.50 pore volumes of steam injected. Figure 8.29 shows that the heat advances immediately into the lower portion of the model for the continuous steamflood without gas injection. Figure 8.30, for the gas injection experiment at the same stage of steam injection, shows a nearly vertical heat advance in the model. Figure 8.31, for the straight steamflood experiment after 1.50 pore volumes of steam was injected, shows that the heat continues to advance more rapidly in the lower portion of the model. Figure 8.32, for the experiment involving gas injection prior to steamflooding, after 1.50 pore volumes of steam was injected, shows that the heat is still quite evenly distributed between the upper and lower portion of the model.

These temperature profiles indicate that without gas injection prior to steamflooding, the steam channeled directly into the bottom water layer, but that with gas injection this problem was mitigated. Whether the gas provided a path at the top of the bead pack, or whether the path was created at the oil water interface is uncertain, due to the limited resolution that can be obtained with only two layers of thermocouples. A thicker model would allow for more layers of thermocouples, but the geometric scaling in the vertical dimension would be lost.

The most significant result of these gas injection experiments in bottom water models, was that the oil recovery response was significantly improved. Figure 8.33 graphically compares the recovery response of continuous steamflooding with (Run 38) and without (Run 39) gas injection prior to steamflooding, in a bottom water reservoir. The steamflood production response for the gas injection experiment is significantly better than the straight steamflood experiment. The ultimate oil recovery is also considerably higher. These results are valid for the oil viscosity simulated (1275 mPa·s), and possibly for lower viscosities. For higher oil viscosities, the beneficial effect of gas would probably be less evident.

Figure 8.32 Temp Profile For Run 39
Injector to Producer Cross-Section
 1.50 Pore Volumes of Steam Injected.

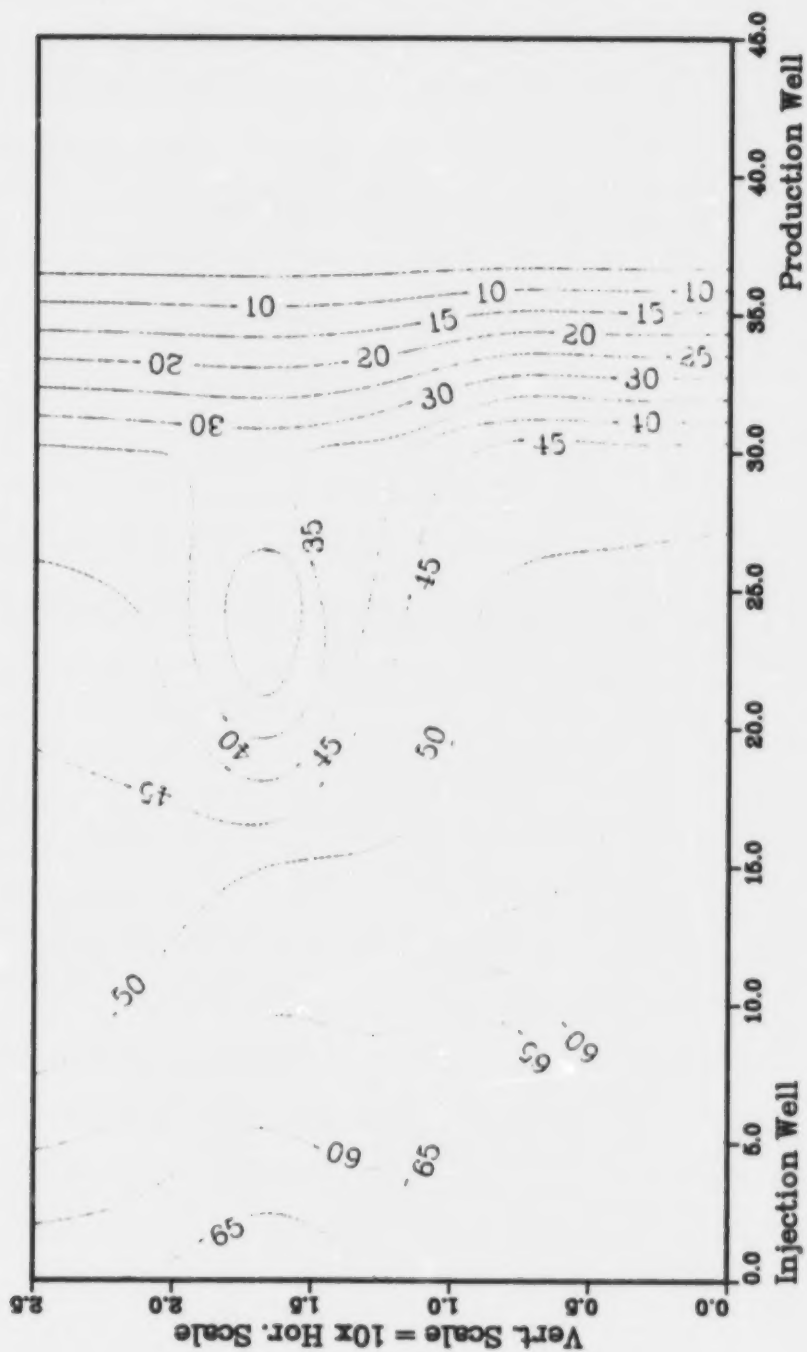
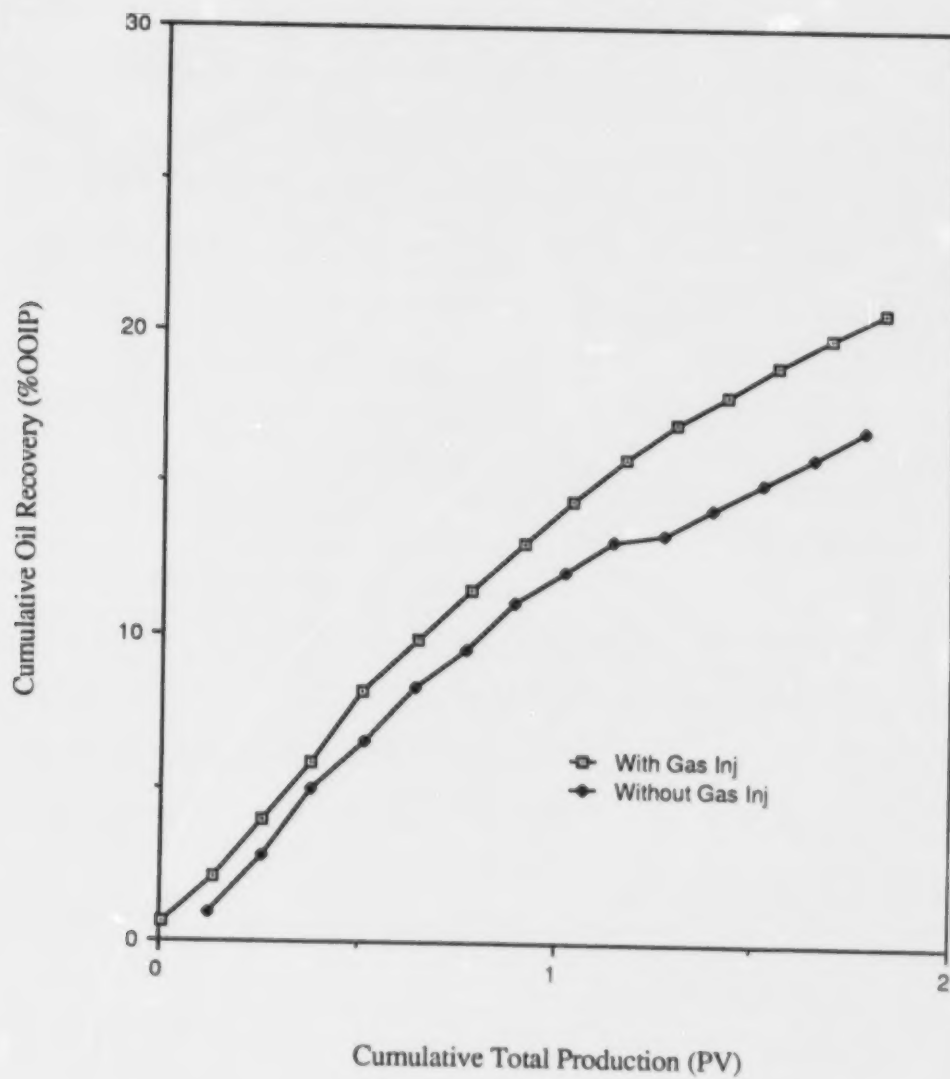


Figure 8.33 Recovery Comparison For Runs 38 & 39



Bottom Water Experiments -- General

Eight experiments were conducted in models with bottom water layers. As noted previously, the bottom water thickness ranged from 2.3 to 19.7% of the total reservoir thickness. Four successful continuous steamflood experiments were performed in models with bottom water. Although there is not sufficient data to draw far reaching conclusions, these runs seem to indicate that there is a minimum bottom water thickness below which the effect of bottom water is small. Figure 8.34 plots the oil recovery for each of the four continuous steamflood experiments at 1.75 pore volumes of cumulative production against the bottom water thickness in the model, as a percentage of the total model thickness. From this plot it can be seen that with a bottom water thickness less than about 10% of the total model thickness, the steamflood oil recovery is similar to the continuous steamfloods in homogeneous packs. However, for a bottom water thickness of greater than 10% of the total model thickness, oil recovery is greatly reduced.

Horizontal Wells

Three steamflood experiments were conducted using horizontal wells. Two of these experiments used a horizontal injector and a horizontal producer set in opposite sides of the model to give a steam drive with parallel horizontal wells. The recovery from these two experiments was similar to that of the continuous steamfloods using vertical wells. The third horizontal well experiment utilized a vertical injector and a horizontal producer for the steam drive. This combination proved to be significantly better than the steam drive with parallel horizontal wells, recovering 29% versus 25% of the original oil in place, after injecting 1.8 pore volume of steam.

Runs 34, 35, and 36 were conducted using horizontal wells. In the first of the three (Run 34) horizontal wells were used for steam injection and oil production. Table 8.16 presents the production response of Run 34 and details the experimental parameters. Figure 8.35 below schematically illustrates the position of the horizontal wells for Run 34.

Figure 8.34 Effect of Bottom Water Thickness on Steamflood Recovery

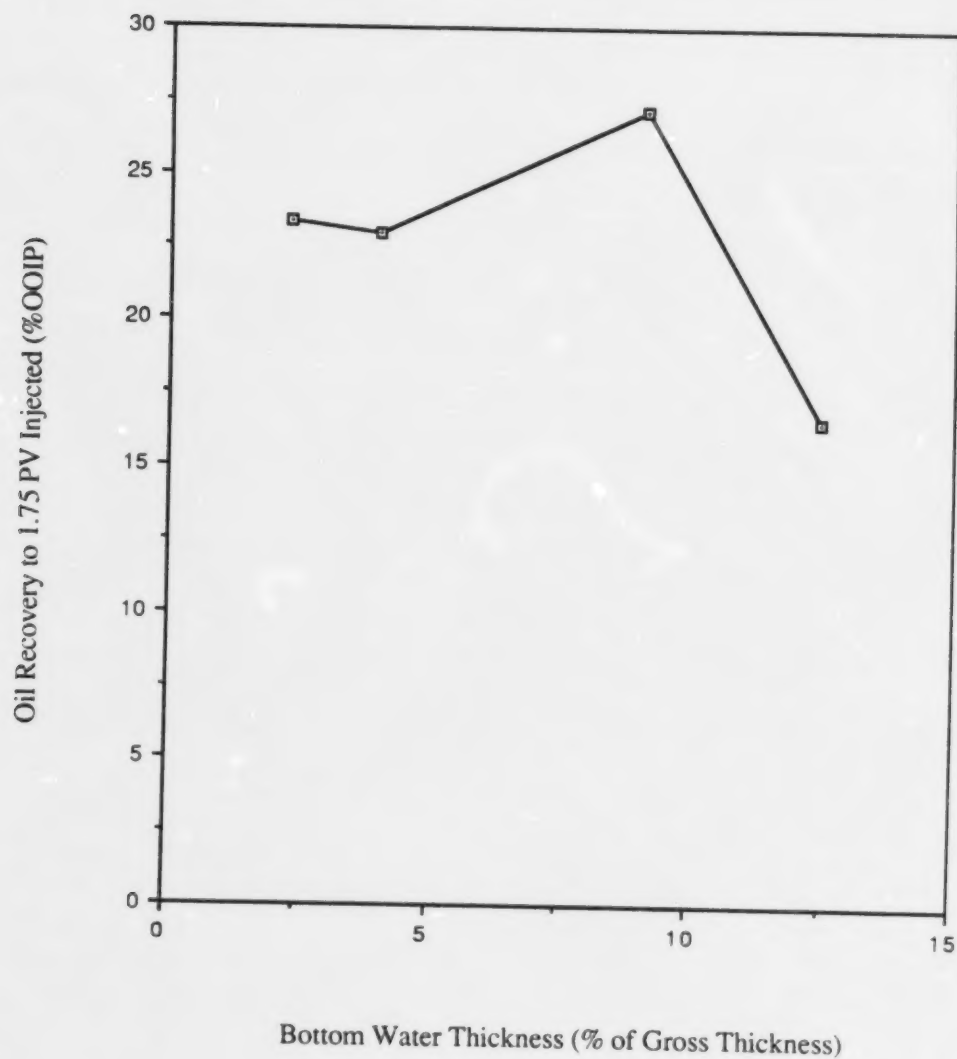


Table 8.16 : Experimental Data For Run 34
Model Simulating the Aberfeldy Reservoir--Continuous Steamflood In Homogeneous Model
Horizontal Injection and Production Well

Pore Volume of Bead Pack: 13760.0 cc
 Porosity of Bead Pack: 32.76 %
 Hydrocarbon Pore Volume: 12885.0 cc
 Initial Oil Saturation: 93.64 %
 Irreducible Water Saturation: 6.36 %
 Initial Model Temperature: 3.0 C
 Water Feed Flow Rate: 199.3 cc
 Steam Feed Flow Rate: 30.1 cc
 Total Steam Injection Rate: 229.4 cc

Sample	Sample Volume (cc)	Water Volume (cc)	Total Cumulative Production (cc)	(PV)	Cumulative Oil Produced (cc)	(%oqip)	Water in Sample(%)	Oil in Sample (%)	Inst. OSR	Cum. OSR
1	1700.0	810.0	1700.0	0.1235	890.0	6.91%	47.65%	52.35%	0.5235	0.5235
2	2000.0	1620.0	3700.0	0.2689	1270.0	9.86%	81.00%	19.00%	0.1900	0.3432
3	1920.0	1665.0	5620.0	0.4084	1525.0	11.84%	86.72%	13.28%	0.1328	0.2714
4	2000.0	1715.0	7620.0	0.5538	1810.0	14.05%	85.75%	14.25%	0.1425	0.2375
5	2025.0	1820.0	9645.0	0.7009	2015.0	15.64%	89.88%	10.12%	0.1012	0.2089
6	2015.0	1780.0	11660.0	0.8474	2250.0	17.46%	88.34%	11.66%	0.1166	0.1930
7	1930.0	1780.0	13590.0	0.9876	2400.0	18.63%	92.23%	7.77%	0.0777	0.1766
8	2040.0	1870.0	15630.0	1.1359	2570.0	19.95%	91.67%	8.33%	0.0833	0.1644
9	1895.0	1760.0	17525.0	1.2736	2705.0	20.99%	92.88%	7.12%	0.0712	0.1544
10	2020.0	1865.0	19545.0	1.4204	2860.0	22.20%	92.33%	7.67%	0.0767	0.1463
11	1810.0	1700.0	21355.0	1.5520	2970.0	23.05%	93.92%	6.08%	0.0608	0.1391
12	1965.0	1840.0	23320.0	1.6948	3095.0	24.02%	93.64%	6.36%	0.0636	0.1327
13	1800.0	1695.0	25120.0	1.8256	3200.0	24.84%	94.17%	5.83%	0.0583	0.1274
14	2125.0	1980.0	27245.0	1.9800	3345.0	25.96%	93.18%	6.82%	0.0682	0.1228

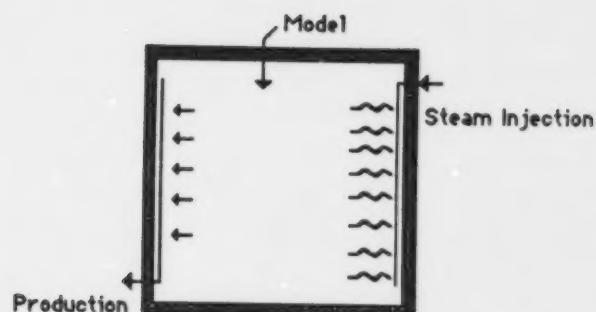


Figure 8.35 Position of Horizontal Wells for Run 34

Run 35 was conducted using a horizontal well as a production well but using a vertical well in the corner of the model as the steam injection well. Table 8.17 details the experimental parameters for this run and gives the production response for this experiment as a function of the pore volumes of steam injected. It can be seen that the oil recovery is considerably higher for Run 35 (with steam injection into the vertical well) than for Run 34 (where steam was injected into a horizontal well). It is interesting to note that when the experiment was finished, an examination of the model revealed that the steam did not disturb a nearly square shaped section of the model as shown in Figure 8.36 below.

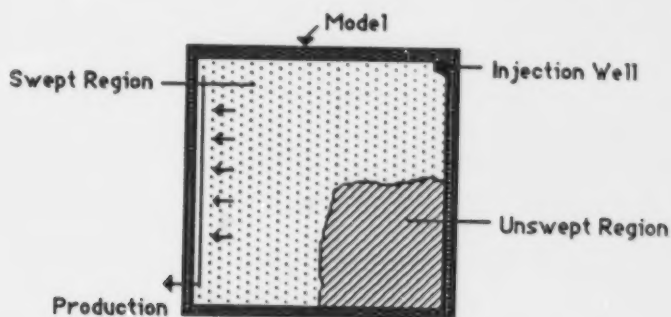


Figure 8.36 Schematic of Model After Run 35

Run 36 utilized horizontal wells as injection and production wells. Table 8.18 presents the data pertaining to this experiment and lists the oil recovery as a function of pore volumes of steam injected. It can be seen that the final recovery was 24.78% after

Table 8.17 : Experimental Data For Run 35
Model Simulating the Aberfeldy Reservoir--Continuous Steamflood In Homogeneous Model
Vertical Injection Well and Horizontal Production Well

Pore Volume of Bead Pack: 14060.0 cc
 Porosity of Bead Pack: 33.47 %
 Hydrocarbon Pore Volume: 12845.0 cc
 Initial Oil Saturation: 91.36 %
 Irreducible Water Saturation: 8.64 %
 Initial Model Temperature: 3.0 C
 Water Feed Flow Rate: 199.3 cc
 Steam Feed Flow Rate: 30.1 cc
 Total Steam Injection Rate: 229.4 cc

Sample	Sample Volume (cc)	Water Volume (cc)	Total Cumulative Production (cc)	Total Cumulative Production (PV)	Cumulative Oil Produced (cc)	(%oqip)	Water in Sample(%)	Oil in Sample (%)	Inst. OSR	Cum. OSR
1	2115.0	950.0	2115.0	0.1504	1165.0	9.07%	44.92%	55.08%	0.5508	0.5508
2	1835.0	1390.0	3950.0	0.2809	1610.0	12.53%	75.75%	24.25%	0.2425	0.4076
3	1940.0	1570.0	5890.0	0.4189	1980.0	15.41%	80.93%	19.07%	0.1907	0.3362
4	1875.0	1615.0	7765.0	0.5523	2240.0	17.44%	86.13%	13.87%	0.1387	0.2885
5	1955.0	1750.0	9720.0	0.6913	2445.0	19.03%	89.51%	10.49%	0.1049	0.2515
6	2060.0	1850.0	11780.0	0.8378	2655.0	20.67%	89.81%	10.19%	0.1019	0.2254
7	1840.0	1655.0	13620.0	0.9687	2840.0	22.11%	89.95%	10.05%	0.1005	0.2085
8	1870.0	1695.0	15490.0	1.1017	3015.0	23.47%	90.64%	9.36%	0.0936	0.1946
9	1990.0	1810.0	17480.0	1.2432	3195.0	24.87%	90.95%	9.05%	0.0905	0.1828
10	1980.0	1820.0	19460.0	1.3841	3355.0	26.12%	91.92%	8.08%	0.0808	0.1724
11	1900.0	1760.0	21360.0	1.5192	3495.0	27.21%	92.63%	7.37%	0.0737	0.1636
12	1925.0	1820.0	23285.0	1.6561	3600.0	28.03%	94.55%	5.45%	0.0545	0.1546
13	2100.0	1975.0	25385.0	1.8055	3725.0	29.00%	94.05%	5.95%	0.0595	0.1467

Table 8.18 : Experimental Data For Run 36
Model Simulating the Aberfeldy Reservoir--Continuous Steamflood In Homogeneous Model
Horizontal Injection and Production Wells

Pore Volume of Bead Pack: 14280.0 cc
 Porosity of Bead Pack: 34.00 %
 Hydrocarbon Pore Volume: 12915.0 cc
 Initial Oil Saturation: 90.44 %
 Irreducible Water Saturation: 9.56 %
 Initial Model Temperature: 3.0 C
 Water Feed Flow Rate: 199.9 cc
 Steam Feed Flow Rate: 30.3 cc
 Total Steam Injection Rate: 230.2 cc

Sample	Sample Volume (cc)	Water Volume (cc)	Total Cumulative Production (cc)	Total Cumulative Production (PV)	Cumulative Oil Produced (cc)	(%o.oip)	Water in Sample(%)	Oil in Sample (%)	Inst. OSR	Cum. OSR
1	1880.0	865.0	1880.0	0.1317	1015.0	7.86%	46.01%	53.99%	0.5399	0.5399
2	1740.0	1400.0	3620.0	0.2535	1355.0	10.49%	80.46%	19.54%	0.1954	0.3743
3	2115.0	1820.0	5735.0	0.4016	1650.0	12.78%	86.05%	13.95%	0.1395	0.2877
4	1930.0	1630.0	7665.0	0.5368	1950.0	15.10%	84.46%	15.54%	0.1554	0.2544
5	2105.0	1910.0	9770.0	0.6842	2145.0	16.61%	90.74%	9.26%	0.0926	0.2195
6	2030.0	1890.0	11800.0	0.8263	2285.0	17.69%	93.10%	6.90%	0.0690	0.1936
7	1840.0	1690.0	13640.0	0.9552	2435.0	18.85%	91.85%	8.15%	0.0815	0.1785
8	2035.0	1900.0	15675.0	1.0977	2570.0	19.90%	93.37%	6.63%	0.0663	0.1640
9	1900.0	1770.0	17575.0	1.2307	2700.0	20.91%	93.16%	6.84%	0.0684	0.1536
10	2010.0	1810.0	19585.0	1.3715	2900.0	22.45%	90.05%	9.95%	0.0995	0.1481
11	1960.0	1860.0	21545.0	1.5088	3000.0	23.23%	94.90%	5.10%	0.0510	0.1392
12	2020.0	1910.0	23565.0	1.6502	3110.0	24.08%	94.55%	5.45%	0.0545	0.1320
13	1910.0	1820.0	25475.0	1.7840	3200.0	24.78%	95.29%	4.71%	0.0471	0.1256

injecting 1.78 pore volumes of steam. This compares very closely to the recovery observed in Run 34, which utilized the same well configuration. Run 35, which used a vertical injector and a horizontal producer, gave considerably better results, even though the steam did not contact a large portion of the reservoir. It would appear that a combination of vertical injectors and horizontal producers may be better suited to such steamflooding operations.

These horizontal well experiments produced good results, perhaps better than the vertical well steamfloods, but the difficulty and added expense of placing horizontal wells in a thin reservoir may limit the applicability of this process.

Solvent Injection Experiment in Homogeneous Model

The injection of a light hydrocarbon slug (solvent) prior to a steamflood of a heavy oil reservoir may prove to be an economical and efficient recovery technique. The process involves a combination of production mechanisms such as miscible displacement, hot waterflooding and steamflooding and is designed to attain high thermal efficiency so to utilize the maximum amount of heat injected into the oil reservoir. Since the solvent injected is used as a buffer it is possible that a considerable amount of the injected solvent slug can be recovered which gives the process a better chance of being economically viable.

The recovery method involves injecting a solvent slug prior to steamflooding in order to displace the heavy oil in the reservoir. The solvent slug displaces the inplace heavy oil at a very unfavourable mobility ratio (the higher the mobility ratio the less efficient the displacement). The ratio of the viscosity of the displaced to the displacing fluid defines mobility ratio. The mobility ratio between the solvent slug and the inplace heavy oil will be more favourable following the displacement of the solvent slug by steam. The more favourable mobility ratio is due to the injected solvent creating a graded viscosity region with the mixture viscosity in the transition zone ranging from the heavy oil viscosity to the solvent viscosity. The graded viscosity region contributes to improving the oil recovery of

the steamflood by creating a more favourable mobility ratio which hinders viscous fingering and results in a more stable displacement.

To date one solvent injection experiment has been carried out on the Aberfeldy reservoir model. Run 40 involved continuously flooding the oil saturated model with the chosen solvent (Heavy Virgin Naphtha). Table 8.19 lists pertinent data recorded from Run 40 and from this information, oil and solvent recoveries were determined. Also presented are the instantaneous oil produced as a percentage of each sample, bead pack characteristics, initial and final oil saturations, solvent injection rate and volume of injected solvent.

Production began shortly after solvent injection was initiated and the majority of this production was solvent. This indicated that solvent channelling may have occurred almost immediately and thus the solventflood was an unstable displacement. The cumulative oil recovery curve (Figure 8.37) is smooth and gradually increases, also suggesting that an oil bank did not form in the model during the experiment.

All samples taken during Run 40 were mainly solvent with the remainder of the sample being oil as evident in Figure 8.38. The gradual drop in oil content of each sample and lack of pressure fluctuations at the production well during the solventflood again suggests that an oil bank did not form due to immediate solvent channelling which is characteristic of an unstable displacement.

Figures 8.39 to 8.46 display the temperature profiles of the model at upper and lower levels for every 0.25 pore volumes of solvent injected during the experiment. These temperature contours indicate that the solvent advanced faster through the upper portion than the lower region of the model. Also the first few profiles suggest that solvent channelling was prevalent.

During the initial stages of the run, channelling started soon after solvent injection. As the run progressed the solvent was dispersed transversely outwards from the swept zone causing an increased oil mobility in parts of the unswept region. The newly mobilized

Table 8.19 Run 40 : Solventflood Performed With Homogeneous Model

Porosity = 33.7 %

Bulk Volume = 42005 cc

Pore Volume = 14140 cc

Initial HC Pore Volume = 13075 cc

Initial Oil Saturation = 92.47 %

Initial Water Saturation = 7.53 %

Total Solvent Injected = 2.25 P.V. (31700 cc)

Solvent Injection Rate = 200 cc/min.

Cylinder No.	Solvent Conc. (%)	Total Volume Prod. (cc)	Cum. HC Vol. Prod.		Oil Prod. (cc)	Cum. Oil Prod. (cc)	Cum. Oil Rec. (%)	Cum. Solvent Rec.		Inst. Oil Prod. % of Sample
			(cc)	(P. V.)				(cc)	(%)	
1	59	1700	1700	0.12	697.00	697.00	5.33	1003.0	3.16	41.3%
2	79	1515	3215	0.23	318.15	1015.15	7.76	2199.9	6.94	21.0%
3	80	1510	4725	0.33	302.00	1317.15	10.07	3407.9	10.75	20.0%
4	84	1120	5845	0.41	179.20	1496.35	11.44	4348.7	13.72	16.0%
5	85	1730	7575	0.54	259.50	1755.85	13.43	5819.2	18.36	15.0%
6	88	1480	9055	0.64	177.60	1933.45	14.79	7121.6	22.47	12.0%
7	87	1705	10760	0.76	221.65	2155.10	16.48	8605.0	27.15	13.0%
8	89	1345	12105	0.86	147.95	2303.05	17.61	9802.1	30.92	11.0%
9	90	1570	13675	0.97	157.00	2460.05	18.81	11215.1	35.38	10.0%
10	91	1455	15130	1.07	130.95	2591.00	19.82	12539.2	39.56	9.0%
11	91	1675	16805	1.19	150.75	2741.75	20.97	14063.5	44.36	9.0%
12	94	1595	18400	1.30	95.70	2837.45	21.70	15562.8	49.09	6.0%
13	94	1895	20295	1.44	113.70	2951.15	22.57	17344.1	54.71	6.0%
14	94	1550	21845	1.54	93.00	3044.15	23.28	18801.1	59.31	6.0%
15	95	1740	23585	1.67	87.00	3131.15	23.95	20454.1	64.52	5.0%
16	95	1680	25265	1.79	84.00	3215.15	24.59	22050.1	69.56	5.0%
17	96	1750	27015	1.91	70.00	3285.15	25.13	23730.1	74.86	4.0%
18	96	1690	28705	2.03	67.60	3352.75	25.64	25352.5	79.98	4.0%
19	95	1790	30495	2.16	89.50	3442.25	26.33	27053.0	85.34	5.0%
20	96	1380	31875	2.25	55.20	3497.45	26.75	28377.8	89.52	4.0%

Oil Recovery = 26.75 %

Solvent Recovery = 89.52

RUN 40: SOLVENTFLOOD CUMULATIVE OIL RECOVERY VS. PORE VOLUMES INJECTED

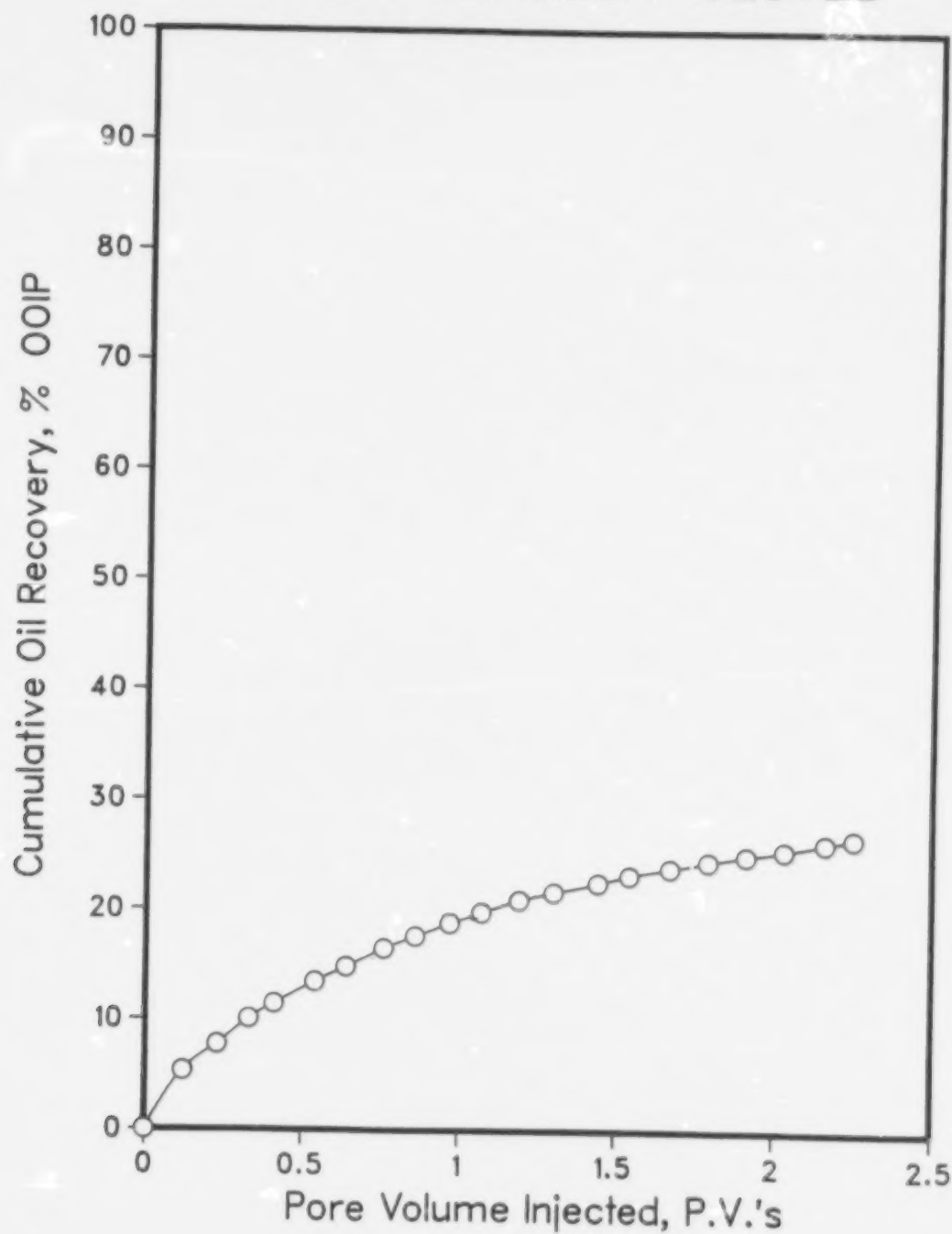


Figure 8.37

RUN 40: SOLVENTFLOOD
INSTANT. OIL PRODUCED IN SAMPLE
VS. CUMULATIVE SOLVENT INJECTED

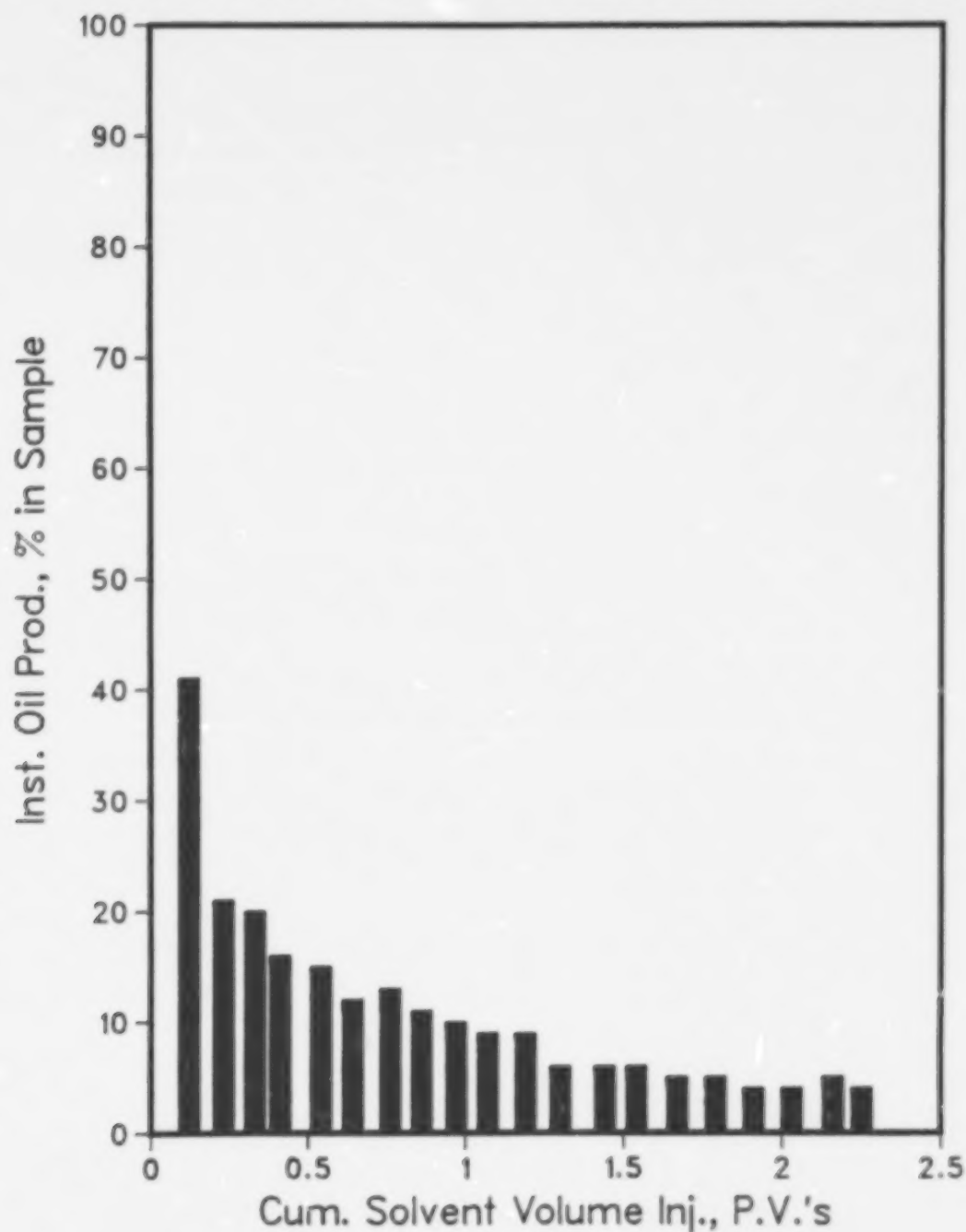


Figure 8.38

Figure 8.39

Run 40: Solventflood of Model

Temperature Profile for
0.25 Pore Volumes Injected

Production Well

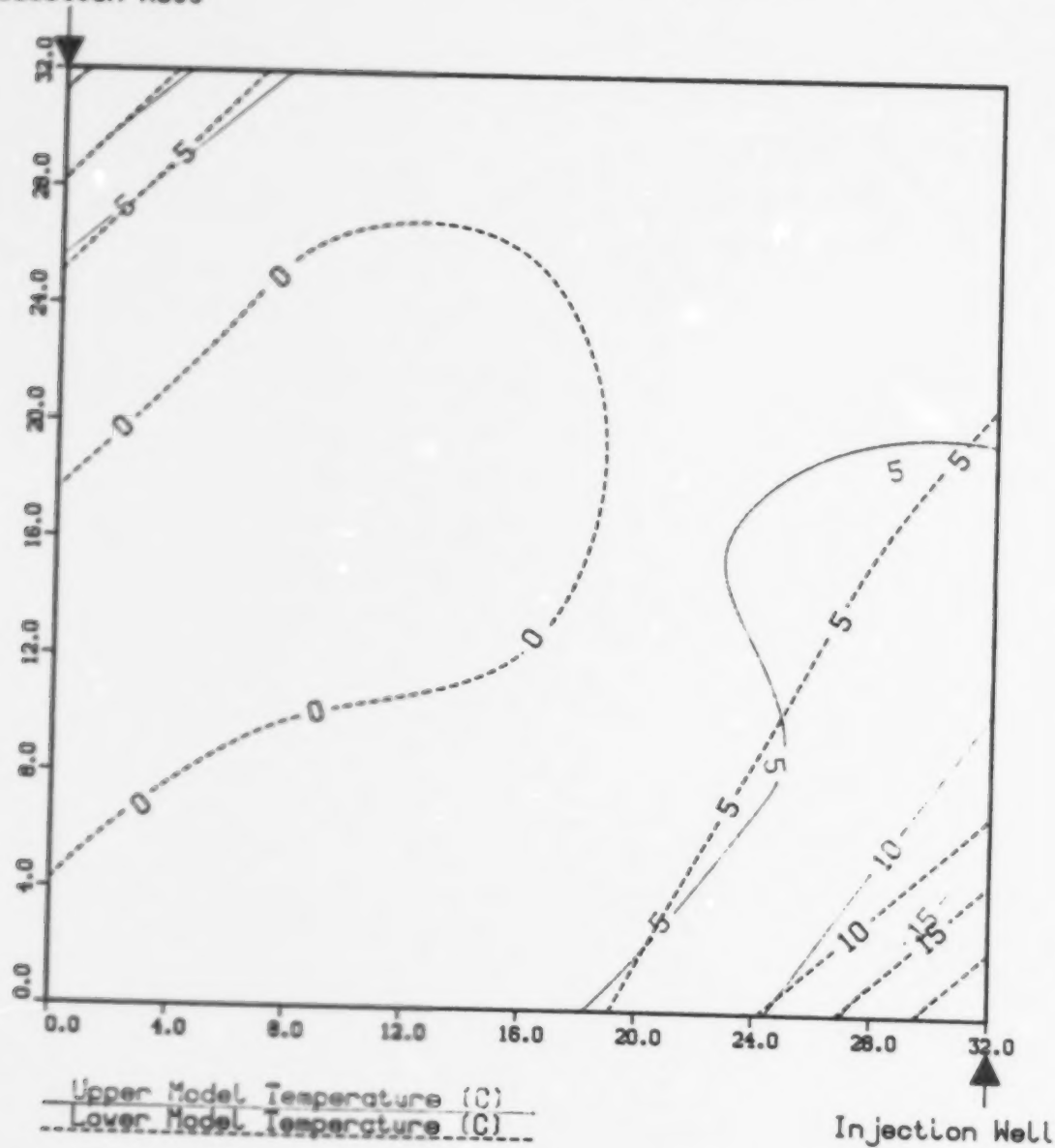


Figure 8.40

Run 40: Solventflood of Model

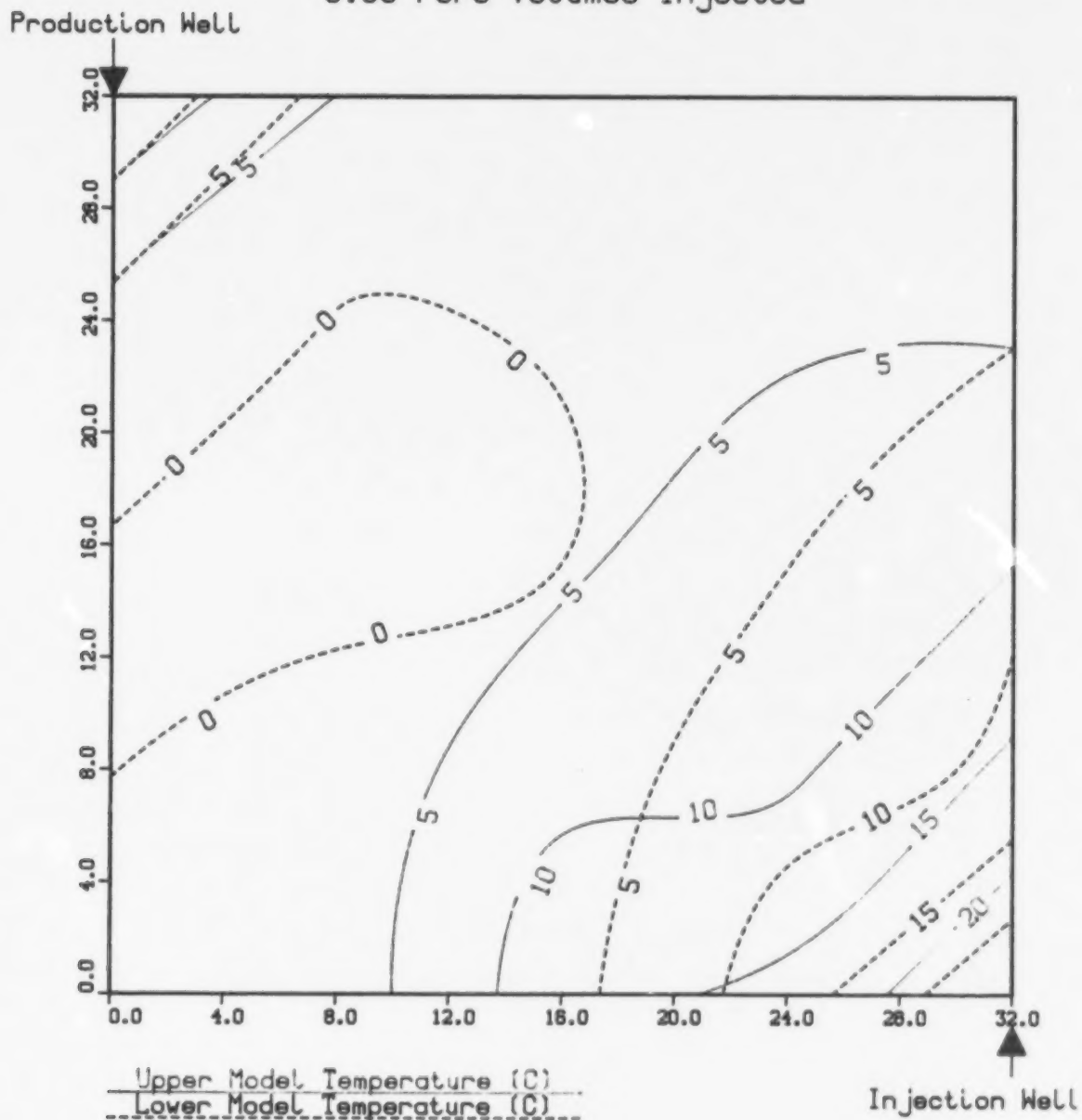
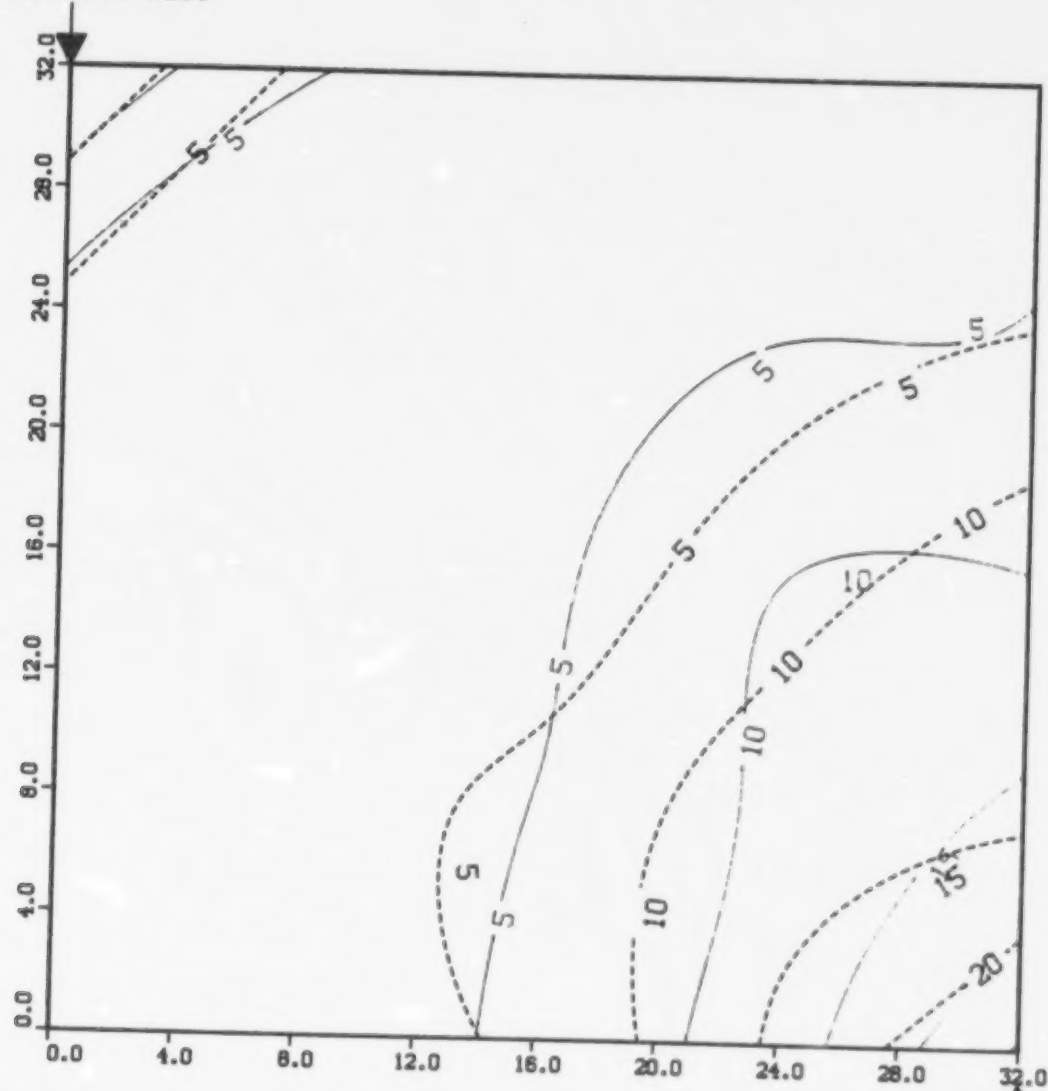
Temperature Profile for
0.50 Pore Volumes Injected

Figure 8.41

Run 40: Solventflood of Model

Temperature Profile for
0.75 Pore Volumes Injected

Production Well



Upper Model Temperature (C)
Lower Model Temperature (C)

Injection Well

Figure 8.42

Run 40: Solventflood of Model

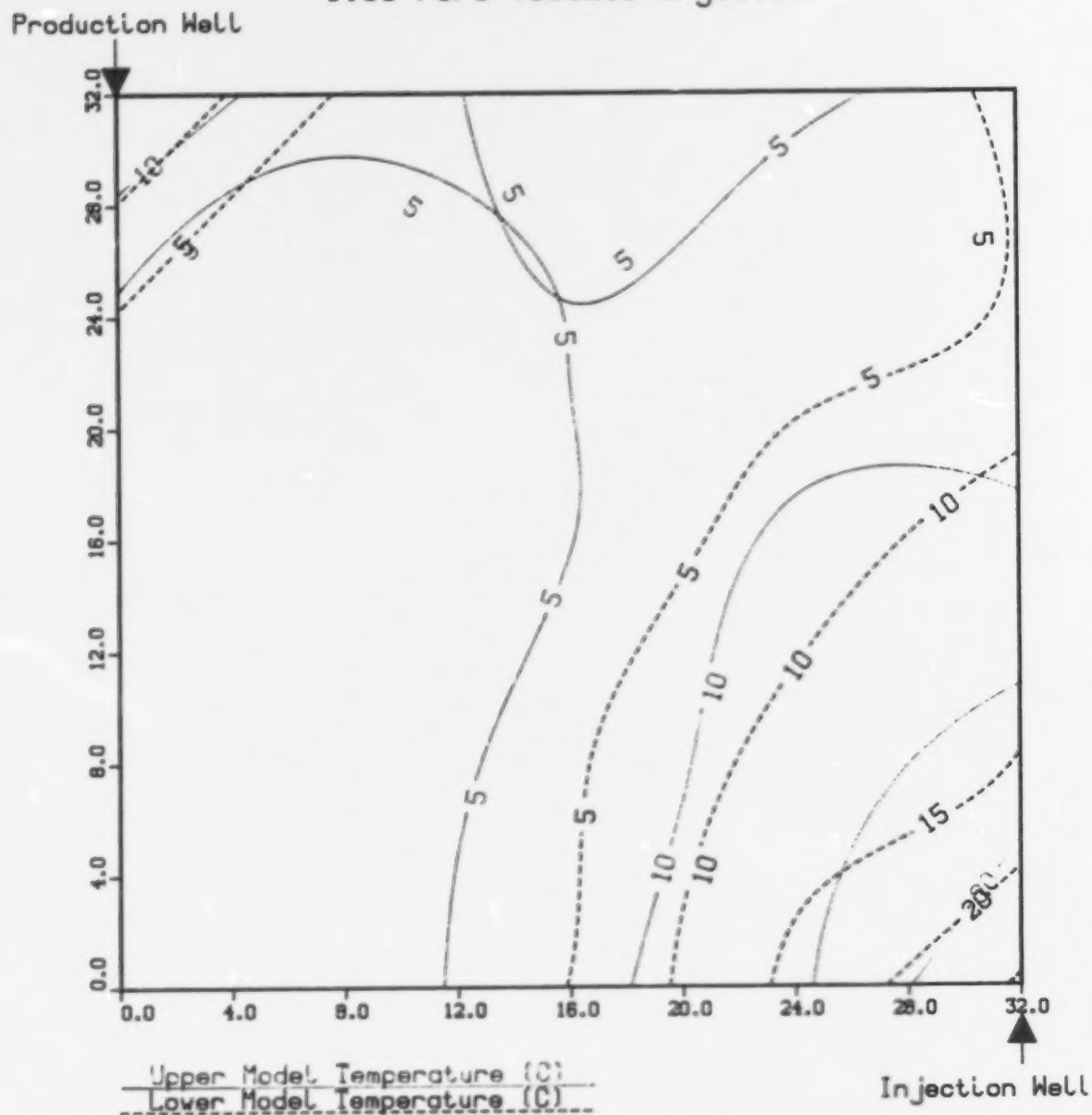
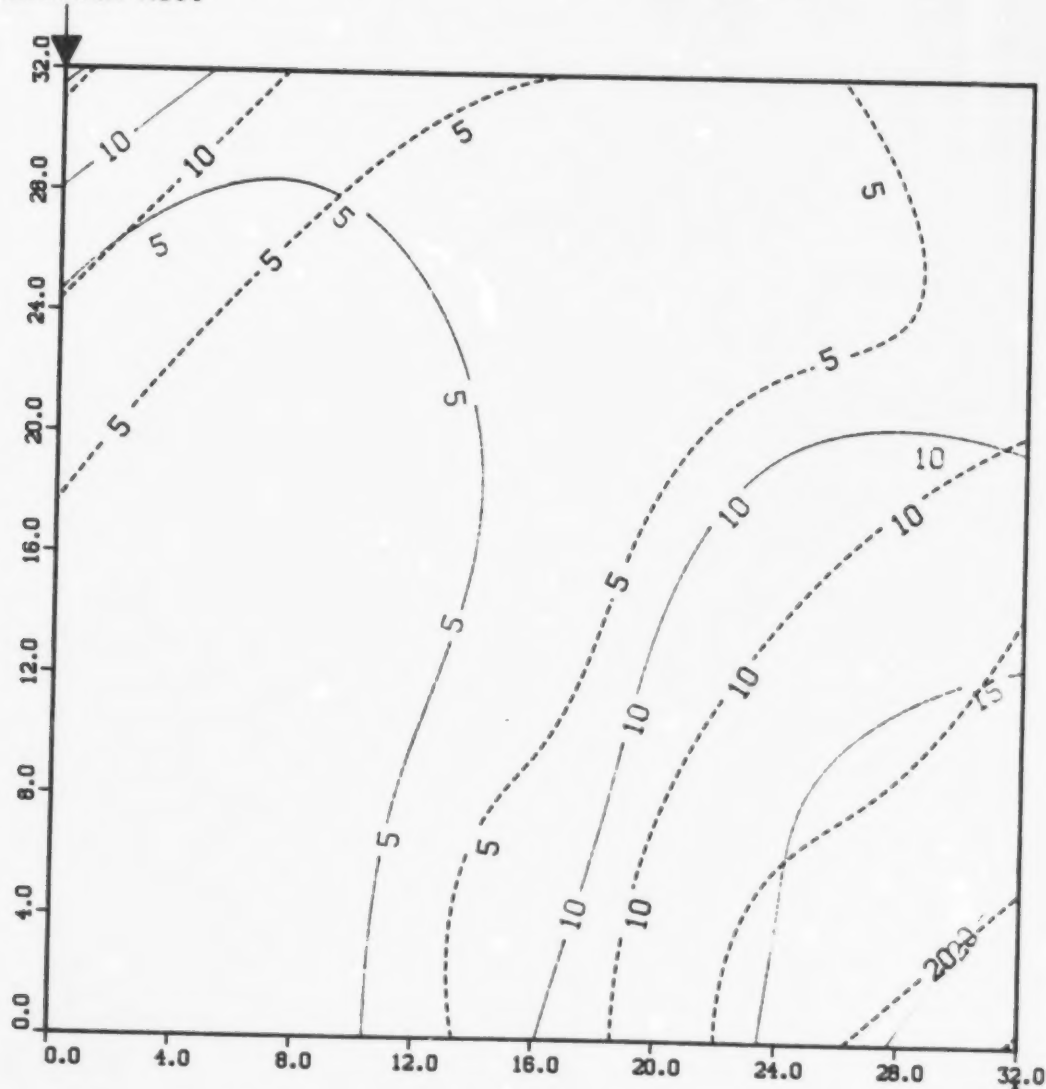
Temperature Profile for
1.00 Pore Volumes Injected

Figure 8.43

Run 40: Solventflood of Model

Temperature Profile for
1.25 Pore Volumes Injected

Production Well



Upper Model Temperature (C)

Lower Model Temperature (C)

Injection Well

Figure 8.44

Run 40: Solventflood of Model

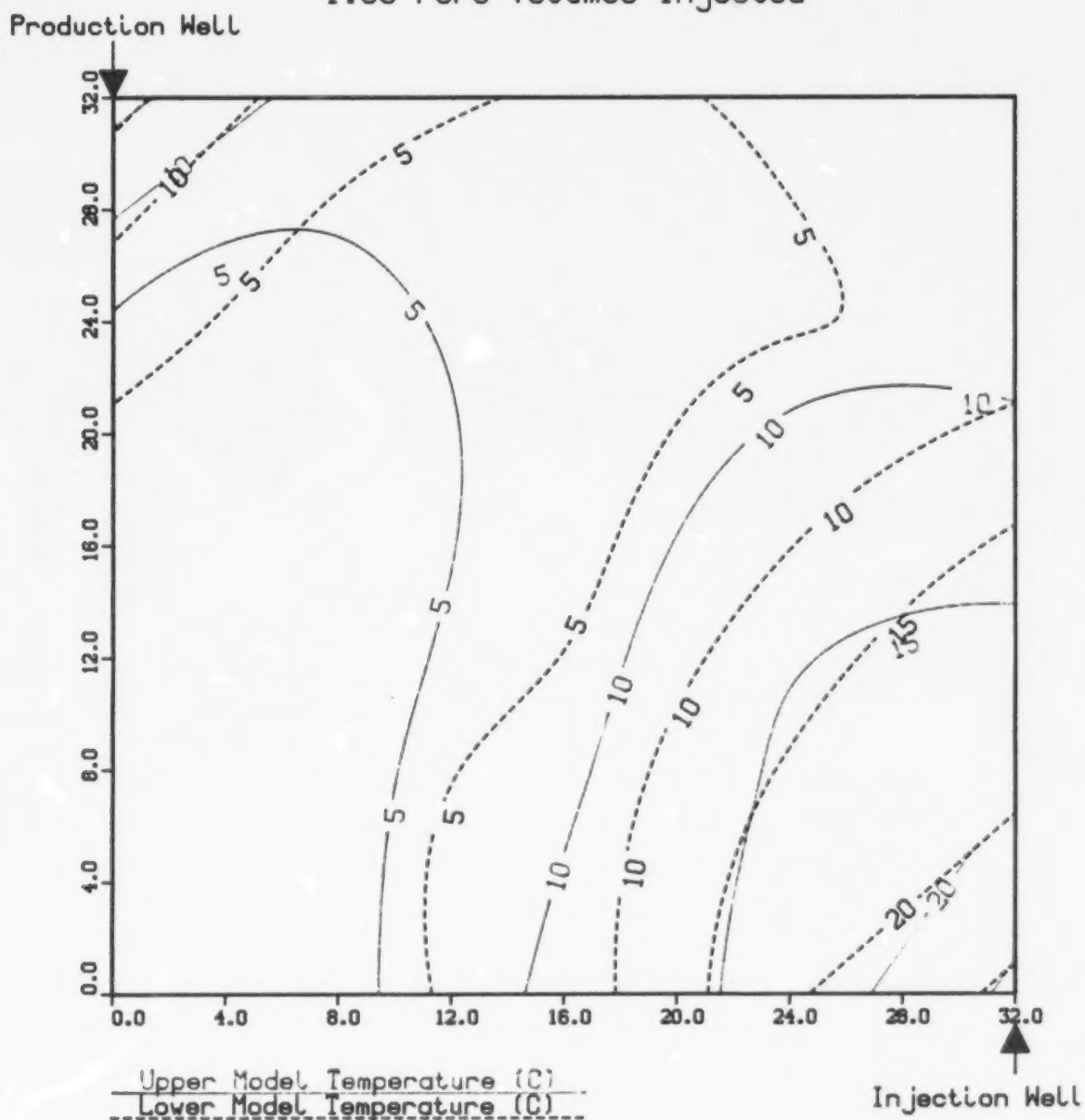
Temperature Profile for
1.50 Pore Volumes Injected

Figure 8.45

Run 40: Solventflood of Model

Temperature Profile for
1.75 Pore Volumes Injected

Production Well

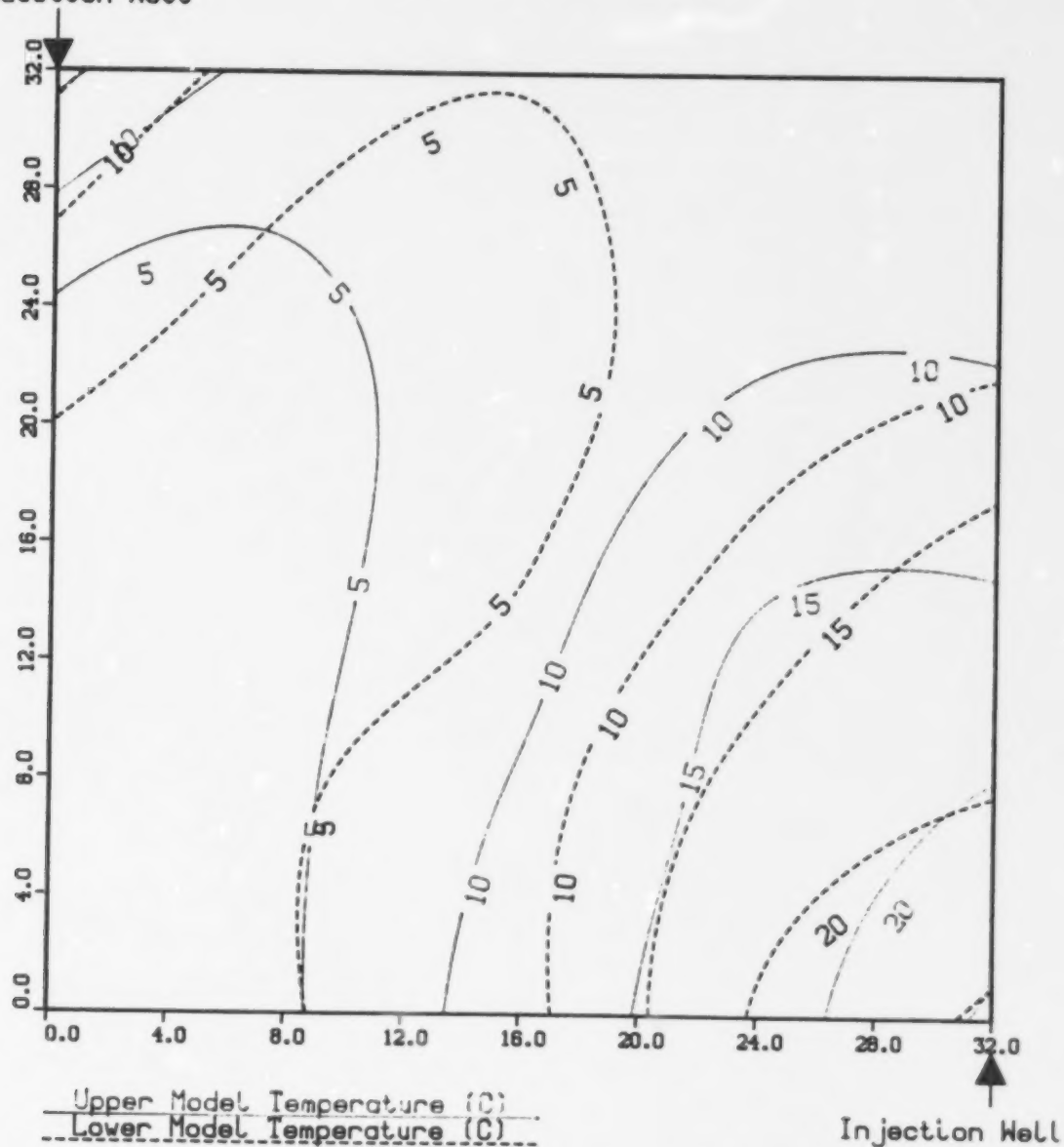
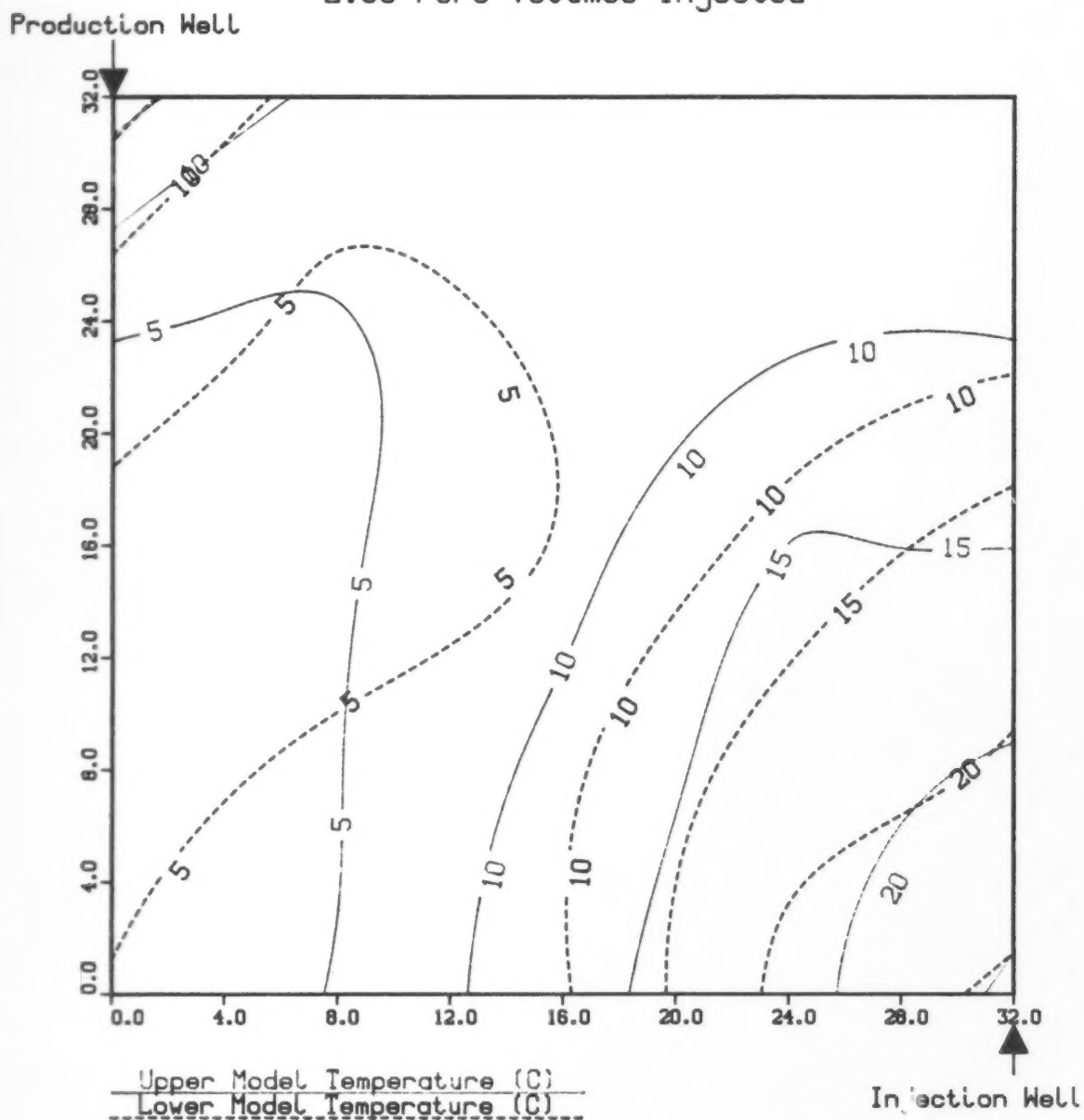


Figure 8.46

Run 40: Solventflood of Model

Temperature Profile for
2.00 Pore Volumes Injected

oil of the unswept area entered the main solvent flow path resulting in the growth of the swept zone. A gradual rise in the cumulative oil recovery then occurred due to the subsequent production of this newly mobilized oil. This rise in cumulative oil recovery can also be partially attributed to the flowing solvent further reducing the oil saturation in the swept zone. The overall low recovery was due to solvent channelling creating a small swept zone which prevented an oil bank from developing and a stable displacement front from being formed.

The oil recovery for Run 40 was relatively poor at 26.75 % which is comparable to previous waterfloods such as Run 7 (26.47 %) and Run 22 (25.91 %). Cumulative solvent recovery was reasonably good at 89.52 %, The good solvent recovery was due to the immediate and continuous solvent channelling during the run. The implementation of a waterflood would be more desirable than the solventflood because it is less expensive to implement and yields about the same oil recovery. Thus for the next few experiments it was decided that solvent in combination with steam should be tested as a recovery technique. In future experiments solvent slug injection prior to steamflooding will be implemented in the reservoir under bottom water conditions.

CONCLUSIONS

This investigation presented simulations of steam injection processes, with a number of novel features. The model examined such phenomena as thermal upgrading, non-Newtonian oil rheology and steam-foam injection in the context of steamflooding. Scaled physical model studies were also carried out for a variety of operating conditions. The important problem of steamflooding bottom water reservoirs was investigated for the first time. Within the framework of this study, the following conclusions were reached:

Numerical Simulations

1. The steam injection simulators were used to simulate steamflooding, cyclic steam stimulation, in three dimensions, including effects such as thermal upgrading of oil, non-Newtonian oil rheology, and injection of a steam-based foam. A wellbore simulator was used to simulate steam pressure and quality changes when multiple steam offtakes are employed in thick formations.
2. Thermal upgrading, non-Newtonian oil rheology, and foam flow are not necessarily important processes in steam injection, but should be included in any simulation. This observation is based upon rather few simulations and approximate representations of these processes. Thermal upgrading is effective in only the high temperature regions of a steamflood, over long periods. Non-Newtonian oil behaviour (in this case, shear-thinning) will affect oil viscosity over the entire reservoir, leading to an increase in oil recovery over the case where the oil viscosity is shear-dependent. Foam injection with steam was only a little more effective than steam alone, within the framework of the foam model used in this work.
3. In bottom water reservoirs, many factors affect steamflood and cyclic steaming performance, the most important of which are: bottom water zone thickness, its oil saturation, vertical and horizontal permeabilities, and completion interval. Vertical permeability makes a difference when it is one-tenth, or less of the horizontal;

- higher values do not seem to make much difference in performance. A mobile oil saturation in the bottom water zone, even though it may be low, can make a bottom water type heavy oil reservoir more attractive for steamflooding.
4. Partially penetrating wells can help avoid communication with a bottom water zone, but the oil-steam ratios would be low in the first few cycles, as compared to wells completed over the entire interval. The latter would produce oil at a much greater water-oil ratio.
 5. If steam is taken off an injection tubing at more than one point, the steam quality at the lower points will be continue to drop. The extent of quality drop depends on the steam offtake rates, steam pressure, surface quality, and time. At a given offtake point in the tubing, the steam quality tends to stabilize with time. Assuming a constant steam quality for two, or more layers, as is the current practice in steam simulation, can lead to optimistic oil recovery estimates, compared to a more realistic simulation, as done in the present study, with the steam quality and pressure varying in time at each layer, with the offtake rates.
 6. History matching of a scaled laboratory experiment of steamflooding showed that considerable adjustments in the "field" relative permeabilities must be made to obtain a match.

Experimental Steamfloods

7. The steam slug process appears to be an efficient and practically viable recovery process for thin heavy oil reservoirs of the Aberfeldy type.
8. For thin, heavy oil reservoirs with bottom water, the injection of a small volume of an inert gas prior to steam injection may to be a suitable method for improving steamflood performance. The injected gas appears to create a flow channel away from the bottom water and allows for a more efficient heating of the reservoir.

9. The results of the experiments indicate that there is some minimum bottom water thickness, approximately 10% of the gross pay thickness, below which the effect of bottom water is small.
10. Steam drive experiments utilizing horizontal wells produced favorable results although the difficulty and added expense involved in placing horizontal wells in thin heavy oil formations may limit the applicability of this process. However, the results of these horizontal well experiments were encouraging and warrant further investigation into the modeling of horizontal well processes in bottom water situations.
11. The use of solvent slugs in combination with steam as a recovery technique may after further investigation prove to be an efficient and economical means of heavy oil recovery from bottom water reservoirs.

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APPENDIX A
TREATMENT OF CONVECTIVE-DIFFUSION TERMS

$$\begin{aligned}
& \frac{\partial}{\partial x} (\rho_o v_{ox} T \Sigma (c_{pi} C_{io})) \\
&= \frac{\partial}{\partial x} \left(\rho_o T \Sigma (c_{pi} C_{io}) \cdot \left(-\frac{k_x k_{ro}}{\mu_o} \frac{\partial \Phi_o}{\partial x} \right) \right) \\
&= -\rho_o T \Sigma (c_{pi} C_{io}) \frac{\partial}{\partial x} \left(\frac{k_x k_{ro}}{\mu_o} \frac{\partial \Phi_o}{\partial x} \right) \Big|_i \\
&\quad - \left(\frac{k_x k_{ro}}{\mu_o} \frac{\partial \Phi_o}{\partial x} \right) \frac{\partial}{\partial x} (\rho_o T \Sigma C_{pi} C_{io}) \Big|_i \\
&= \rho_o T \Sigma (c_{pi} C_{io}) \frac{A_x k_x k_{ro}}{\mu_o \Delta x} \Big|_{i+1/2} (\Phi_{o_{i+1}} - \Phi_{o_i}) \\
&\quad - \frac{A_x k_x k_{ro}}{\mu_o \delta x} \Big|_{i-1/2} (\Phi_{o_i} - \Phi_{o_{i-1}}) \\
&\quad - \frac{k_x k_{ro}}{\mu_o} \frac{\partial \Phi_o}{\partial x} \Big|_i S_{i-1} (\rho_o T \Sigma c_{pi} C_{io})_{i-1} \\
&\quad + S_i (\rho_o T \Sigma c_{pi} C_{io})_i + S_{i+1} (\rho_o T \Sigma c_{pi} C_{io})_{i+1}
\end{aligned}$$

where for block i

$$\Delta x = 1/2 (\Delta x_i + \Delta x_{i+1})$$

$$\delta x = 1/2 (\Delta x_i + \Delta x_{i-1})$$

$$S_i = \frac{2(\Delta x_{i+1} - \Delta x_{i-1})}{(\Delta x_i + \Delta x_{i+1})(\Delta x_i + \Delta x_{i-1})}$$

APPENDIX B

FORTRAN 77 PROGRAM FOR SOLVING A 6X6 BLOCK DIAGONAL MATRIX

Listing of MOON80 at 09:39:21 on JUN 16, 1987 for CCID=MKKF on UALRAMTS

```

1 C MAHNAZ KASRAIE * OCT. 10, 1986 * PGM TO SOLVE A 6X6 BLOCK BAND MATRIX
2 C ARISING FROM A SYSTEM OF SIX IMPLICIT FINITE DIFF. EQNS.
3 C WE LL DEFINE THE Z,B,D,E,F,H,S ARRAYS, WHICH COME FROM THE FDEONS.
4 C AND CREATE THE A BAND MATRIX, AND PRINT IT OUT TO SEE IF ALL THE A S ARE
5 C IN THE RIGHT POSITIONS. Z=1, B=2, D=3, E=4, F=5, H=6, S=7,
6 C AND THEN PROCEED TO OBTAIN THE SOLUTION VECTOR.
7 C IMPLICIT REAL*8 (A-H,O-S)
8 C DIMENSION Z(7,7,3,6,6),B(7,7,3,6,6),D(7,7,3,6,6),E(7,7,3,6,6),
9 C 1F(7,7,3,6,6),H(7,7,3,6,6),S(7,7,3,6,6),X(882)
10 C 2,NEL(500),NS(82000)
11 C DATA Z,B,D,E,F,H,S,X/5292*1,DO,5292*2,DO,5292*3,DO,5292*4,DO,
12 C 15292*5,DO,5292*6,DO,5292*7,DO,882*0,DO/
13 C COMMON/XLB/AS(82000),QS(500)
14 C NEL(IROW) IS THE LAST AS( ) # IN ROW NO. IROW: NEONS=IROW IS THE ROW #.
15 C XX IS THE SUM OF ELEMENTS IN A ROW TO GENERATE THE CONSTANT VECTOR, QS( )
16 C FOR IROW: ALL THESE ARE ONLY FOR TESTING, MAY BE REMOVED LATER: THESE LINES
17 C ARE IDENTIFIED BY A STATEMENT # BEGINNING WITH 9999- FOR CONVENIENCE.
18 C
19 C
20 C
21 C WRITE(6,1)
22 C 1 FORMAT(/,'ENTER : NX, NY, NZ, NA')
23 C
24 C READ*,NX,NY,NZ,NA
25 C NX=2
26 C NY=5
27 C NZ=5
28 C NA=6
29 C
30 C 11112 VAL=876579
31 C DO 11111 I=1,NX
32 C DO 11111 J=1,NY
33 C DO 11111 K=1,NZ
34 C DO 11111 L=1,NA
35 C DO 11111 M=1,NA
36 C U=URAND(VAL)
37 C Z(I,J,K,L,M)=Z(I,J,K,L,M)*U
38 C B(I,J,K,L,M)=B(I,J,K,L,M)*U
39 C U=URAND(VAL)
40 C D(I,J,K,L,M)=D(I,J,K,L,M)*U
41 C U=URAND(VAL)
42 C E(I,J,K,L,M)=E(I,J,K,L,M)*U
43 C U=URAND(VAL)
44 C F(I,J,K,L,M)=F(I,J,K,L,M)*U
45 C U=URAND(VAL)
46 C H(I,J,K,L,M)=H(I,J,K,L,M)*U
47 C U=URAND(VAL)
48 C S(I,J,K,L,M)=S(I,J,K,L,M)*U
49 C 11111 CONTINUE
50 C
51 C NXY=NX*NY
52 C NXZ=NX*NZ
53 C NYZ=NY*NZ
54 C NEONS=NXY*NZ
55 C
56 C IF(NXY.EQ.NEONS.OR.NYZ.EQ.NEONS.OR.NYZ.EQ.NEONS)GO TO 12
57 C
58 C

```

```

59 IF(NXZ.GT.NBANDS)NBANDS=NXZ
60 IF(NYZ.GT.NBANDS)NBANDS=NYZ
61 GO TO 13
62 C
63 12 NBANDS=NX
64 IF(NY.GT.NBANDS)NBANDS=NY
65 IF(NZ.GT.NBANDS)NBANDS=NZ
66 C
67 IF(NX.EQ.NEONS.OR.NY.EQ.NEONS.OR.NZ.EQ.NEONS) NBANDS=1
68 IF(NEONS.EQ.1)NBANDS=0
69 C
70 13 NBANDS=NBANDS*NA+NA-1
71 NEONS=NEONS*NA
72 C
73 MC=1+2*NBANDS
74 MA=NEONS*MC-NBANDS*(NBANDS+1)/2
75 NF IN=MA-NBANDS*(NBANDS+1)/2
76 C
77 DO 10 M=1,MA
78 AS(M)=O.DO
79 C
80 DO 11 M=1,NEONS
81 QS(M)=O.DO
82 C
83 NOFSET=0
84 MOFSET=0
85 INCR=0
86 C
87 DO 101 K=1,NZ
88 KK=NX*(K-1)
89 C
90 DO 101 J=1,NV
91 JK=NX*(J-1)+KK
92 C
93 DO 101 I=1,NX
94 IJK=I+JK
95 C
96 DO 101 M=1,NA
97 NROW=(IJK-1)*NA+M
98 C
99 DO 100 L=1,NA
100 IJKL=(IJK-1)*NA+L
101 C
102 AS(NOFSET+IJKL)=E(I,J,K,L,M)
103 QS(NROW)=QS(NROW)+E(I,J,K,L,M)
104 C
105 IF(I.EQ.1)GO TO 50
106 C
107 AS(NOFSET+IJKL-NA)=D(I,J,K,L,M)
108 QS(NROW)=QS(NROW)+D(I,J,K,L,M)
109 C
110 IF(I.EQ.1)GO TO 60
111 C
112 AS(NOFSET+IJKL-NA)=D(I,J,K,L,M)
113 QS(NROW)=QS(NROW)+D(I,J,K,L,M)
114 C
115 IF(I.EQ.NX)GO TO 60
116 C

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117 AS(NOFSET+I,J,KL+NA)=F(I,J,K,L,M)
118 OS(NROW)=OS(NROW)+F(I,J,K,L,M)
119
120 C 60 IF(J.EQ.1)GO TO 70
121
122 C AS(NOFSET+I,J,KL-NA*NX)=B(I,J,K,L,M)
123 OS(NROW)=OS(NROW)+B(I,J,K,L,M)
124
125 C 70 IF(J.EQ.NY)GO TO 80
126
127 C AS(NOFSET+I,J,KL+NA*NX)=H(I,J,K,L,M)
128 OS(NROW)=OS(NROW)+H(I,J,K,L,M)
129
130 C 80 IF(K.EQ.1)GO TO 90
131
132 C AS(NOFSET+I,J,KL-NA*NX)=Z(I,J,K,L,M)
133 OS(NROW)=OS(NROW)+Z(I,J,K,L,M)
134
135 C 90 IF(K.EQ.NZ)GO TO 100
136
137 C AS(NOFSET+I,J,KL+NA*NX)=S(I,J,K,L,M)
138 OS(NROW)=OS(NROW)+S(I,J,K,L,M)
139
140 C 100 CONTINUE
141
142 C MOFSET=MOFSET+NBANDS+1+INCR
143 NEL(NROW)=MOFSET
144
145 C NOFSET=MOFSET
146 IF(NROW.GT.NBANDS)NOFSET=MOFSET-(NROW-NBANDS)
147 IF(NROW.LT.NEONS-NBANDS)INCR=INCR+1
148 IF(NROW.GT.NBANDS)INCR=INCR-1
149
150 C 101 CONTINUE
151
152 C PRINT OUT THE ORIGINAL MATRIX USING THE AS ARRAY; WE HAVE NEONS AND NEL(NEONS)
153 NST=1
154 DO 200 I=1,NEONS
155 K=NEL(I)
156 DO 210 MM=NST,K
157 MS(MM)=IDINT(AS(MM))
158 NDIF=K-NST
159 NQ$=IDINT(Q$(I))
160 PRINT 300,I,NST,K,NDIF,NQ$,(MS(J),J=NST,K)
161 NST=K+1
162
163 C 200 CONTINUE
164 301 FORMAT(' ',40(F3,1,X))
165 300 FORMAT(' ',I3,1X,I4,1X,I4,1X,I4,1X,I3,1X,10B11)
166
167 C PRINT*,NBANDS,NEONS,NFIN,NEL(NEONS)
168 CALL XELB(NBANDS,NEONS,NFIN)
169 PRINT 33333,(Q$(I),I=1,NEONS)
170 33333 FORMAT(' ',8(F9.7,1X))
171
172 C NBANDS IS NO. OF DIAGONALS ABOVE MAIN DIAGONAL; NEO IS NO. OF EONS
173 C NFIN IS THE TOTAL NO. OF A'S; ONLY NEEDED FOR PRINTOUT IN XELB
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175 IMPLICIT REAL*8(A-H,O-$)
176 DIMENSION A(82000),BB(500)
177 COMMON/XLB/AS(82000),QS(500)
178 EQUIVALENCE (AS,A), (QS,BB)
179 PRINT*,(AS(I),I=1,NFIN)
180 PRINT*,(QS(I),I=1,NEQ)
181 M=NEQ
182 N=1
183 MUD=NX
184 MLD=NX
185 EPS=1.D-8
186 IF(MLD)47,1,1
187 1 IF(MUD)47,2,2
188 2 MC=1+MLD+MUD
189 IF(MC+1-M-M)3,3,47
190 3 IF(MC-M)5,5,4
191 4 MC=M
192 5 MU=MC-MUD-1
193 ML=MC-MLD-1
194 MR=M-ML
195 MZ=(MU*(MU+1))/2
196 MA=M+MC-(ML*(ML+1))/2
197 NM=N*M
198 IER=0
199 PIV=0.D0
200 IF(MLD)14,14,6
201 6 JJ=NA
202 J=MA-MZ
203 KST=J
204 DO 9 K=1,KST
205 TB=A(J)
206 A(JJ)=TB
207 TB=DABS(TB)
208 IF(TB-PIV)8,8,7
209 7 PIV=TB
210 8 J=J-1
211 9 JJ=JJ-1
212 IF(MZ)14,14,10
213 10 JJ=1
214 J=1+MZ
215 IC=1+MUD
216 DO 13 I=1,MJ
217 DO 12 K=1,MC
218 A(JJ)=0.D0
219 IF(K-IC)11,11,12
220 11 A(JJ)=A(J)
221 J=J+1
222 12 JJ=JJ+1
223 13 IC=IC+1
224 14 TOL=EPS*PIV
225 KST=1
226 IDST=MC
227 IC=MC-1
228 DO 38 K=1,M
229 IF(K-MR-1)16,16,15
230 15 IDST=IDST-1
231 16 ID=IDST
232 ILR=K+MLD

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Listing of MOON80 at 09:39:21 on JUN 16, 1987 for CCID=MKKF on UALRAMTS

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233 IF(ILR-M)18,18,17
234 17 ILR=M
235 18 II=KST
236 PIV=O.DO
237 DO 22 I=K,ILR
238 TB=DABS(A(II))
239 IF(TB-PIV)20,20,19
240 19 PIV=TB
241 J=I
242 JJ=II
243 20 IF(I-MR)22,22,21
244 21 ID-ID-1
245 22 II-II+ID
246 IF(PIV)47,47,23
247 23 IF(IER)26,24,26
248 24 IF(PIV-TOL)25,25,26
249 25 IER=K-1
250 26 PIV=1.DO/A(JJ)
251 ID=J-K
252 DO 27 I=K,NM,M
253 II=I+ID
254 TB=PIV*BB(II)
255 88(II)=BB(I)
256 27 88(II)=TB
257 II=KST
258 J=JJ+IC
259 DO 28 I=JJ,J
260 TB=PIV*A(I)
261 A(I)=A(II)
262 A(II)=TB
263 28 II-II+1
264 IF(K-ILR)29,34,34
265 29 ID=KST
266 II=K+1
267 MU=KST+1
268 MZ=KST+IC
269 DO 33 I=II,ILR
270 ID=ID+MC
271 JJ=I-MR-1
272 IF(JJ)31,31,30
273 30 ID=ID-JJ
274 31 PIV=-A(ID)
275 J=ID+1
276 DO 32 JJ=MJ,MZ
277 A(J-1)=A(J)+PIV*A(JJ)
278 32 J=J+1
279 A(J-1)=O.DO
280 J=K
281 DO 33 JJ=I,NM,M
282 88(JJ)=88(JJ)+PIV*BB(J)
283 33 J=J+M
284 34 KST=KST+MC
285 IF(ILR-MR)36,35,35
286 IC=IC-1
287 36 ID=K-MR
288 IF(ID)38,38,37
289 37 KST=KST-ID
290 38 CONTINUE

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291 IF(MC-1)46,46,39
292 IC=2
293 KST=MA+ML-MC+2
294 II=M
295 DO 45 I=2,M
296 KST=KST-MC
297 II=II-1
298 J=II-MR
299 IF(J)41,41,40
300 KST=KST+J
301 DO 43 J=II,NM,M
302 TB=BB(J)
303 MZ=KST+IC-2
304 ID=J
305 DO 42 JJ=KST,MZ
306 ID=ID+1
307 42 TB=TB-A(JJ)*BB(ID)
308 43 BB(J)=TB
309 IF(IC-MC)44,45,45
310 44 IC=IC+1
311 45 CONTINUE
312 46 RETURN
313 47 IER=-1
314 PRINT 48,IER
315 48 FORMAT('O',IER,' ',IS)
316 RETURN
317 END

```

APPENDIX C
TABULATED DATA FOR SELECTED SIMULATIONS

Table: C.1
Simulation Results For Run ABRS 1 (No Bottom Water)
(ABERFELDY)

Legend:

T : Time, Days
OPR : Oil Production Rate, Bbls/Day
WPR : Water Production Rate, Bbls/Day
WOR : Cumulative Water-Oil Ratio, Bbl/Bbl
CSI : Cumulative Steam Injected, Bbls
OSR : Cumulative Oil-Steam Ratio, Bbl/Bbl

T	OPR	WPR	WOR	CSI	OSR
44.1	19.39	248.98	12.84	26441	0.0324
72.4	19.74	280.34	14.20	43424	0.0325
110.2	20.67	335.40	16.23	66098	0.0330
159.5	27.52	468.79	17.03	95686	0.0352
201.8	36.50	562.39	15.41	121107	0.0395
241.2	49.14	618.93	12.59	144715	0.0451
275.7	53.91	645.91	11.98	165401	0.0504
318.9	61.44	666.86	10.85	191342	0.0567
363.0	71.94	680.37	9.46	217825	0.0634
397.2	83.58	689.04	8.24	238314	0.0692
438.6	105.51	696.03	6.60	263184	0.0778
483.0	154.13	680.26	4.41	289789	0.0910
515.3	218.08	718.76	3.30	309163	0.1047
559.8	292.39	762.70	2.61	335913	0.1339
599.7	391.77	1129.33	2.88	359838	0.1626
640.8	453.14	1171.98	2.59	384507	0.1983
679.3	495.10	872.89	1.76	407573	0.2315
720.9	582.36	747.13	1.28	432567	0.2701
758.1	657.15	670.27	1.02	454874	0.3082
802.9	788.31	671.95	0.85	481723	0.3592
840.3	1009.93	746.02	0.74	504158	0.4092

Table: C.2
Simulation Results For Run ABRS 2 **Bottom Water**
(ABERFELDY)

Legend:

T : Time, Days
 OPR : Oil Production Rate, Bbls/Day
 WPR : Water Production Rate, Bbls/Day
 WOR : Cumulative Water-Oil Ratio, Bbl/Bbl
 CSI : Cumulative Steam Injected, Bbls
 OSR : Cumulative Oil-Steam Ratio, Bbl/Bbl

T	OPR	WPR	WOR	CSI	OSR
58.2	8.90	61.09	6.86	34938	0.0152
110.3	8.96	171.73	19.17	66199	0.0151
173.2	12.59	279.93	22.23	103926	0.0163
225.7	15.48	362.63	23.42	135427	0.0181
265.7	17.39	419.31	24.11	159427	0.0197
325.7	19.92	493.72	24.78	195427	0.0219
385.7	22.19	555.73	25.05	231427	0.0241
445.7	24.34	606.62	24.92	267427	0.0261
485.7	25.79	635.25	24.63	291427	0.0275
545.7	28.12	671.61	23.88	327427	0.0294
605.7	30.85	701.57	22.74	363427	0.0315
659.8	34.51	742.41	21.51	395888	0.0334
719.1	40.39	802.80	19.87	431452	0.0358
769.3	45.83	818.61	17.86	461611	0.0383
829.3	52.80	830.69	15.73	497611	0.0417
889.3	53.34	832.59	15.61	533611	0.0448
929.3	53.70	830.37	15.46	557611	0.0468
989.3	54.69	830.39	15.18	593611	0.0494
1045.6	56.07	832.00	14.84	627339	0.0517
1100.0	66.88	1016.96	15.20	660000	0.0542

Table: C.3
Simulation Results For Run ABRS 3 (No Bottom Water)
(ABERFELDY)

Legend:

T : Time, Days
 OPR : Oil Production Rate, Bbls/Day
 WPR : Water Production Rate, Bbls/Day
 WOR : Cumulative Water-Oil Ratio, Bbl/Bbl
 CSI : Cumulative Steam Injected, Bbls
 OSR : Cumulative Oil-Steam Ratio, Bbl/Bbl

T	OPR	WPR	WOR	CSI	OSR
57.5	19.50	254.26	13.04	34514	0.0324
100.7	20.34	310.08	15.24	60399	0.0328
160.7	25.64	429.55	16.75	96399	0.0348
221.9	39.66	562.33	14.18	133138	0.0408
281.8	52.10	631.96	12.13	169060	0.0494
324.2	58.74	661.51	11.26	194500	0.0552
387.0	72.72	685.67	9.43	232198	0.0642
440.6	93.58	696.53	7.44	264387	0.0733
498.0	145.08	696.99	4.80	298816	0.0878
544.0	245.00	712.40	2.91	326410	0.1088
608.3	249.05	699.98	2.81	364982	0.1405
657.9	277.49	721.62	2.60	394728	0.1634
715.3	323.78	691.44	2.14	429155	0.1909
769.3	558.73	987.30	1.77	461566	0.2266
825.3	849.51	1083.01	1.27	495211	0.2935
881.2	786.55	743.81	0.95	528696	0.3732
935.3	702.34	657.65	0.94	561213	0.4183
989.8	792.09	661.19	0.84	593882	0.4658
1045.4	938.10	524.76	0.56	627264	0.5176
1100.0	1578.38	1237.53	0.78	660000	0.5915

Table: C.4
Simulation Results For Run ABR5 4 (No Bottom Water)
(ABERFELDY)

Legend:

T : Time, Days
 OPR : Oil Production Rate, Bbls/Day
 WPR : Water Production Rate, Bbls/Day
 WOR : Cumulative Water-Oil Ratio, Bbl/Bbl
 CSI : Cumulative Steam Injected, Bbls
 OSR : Cumulative Oil-Steam Ratio, Bbl/Bbl

T	OPR	WPR	WOR	CSI	OSR
42.1	19.60	316.43	16.14	50574	0.0162
77.9	31.36	645.38	20.58	93445	0.0182
122.0	45.02	963.51	21.40	146468	0.0235
159.4	55.71	1126.44	20.22	191254	0.0280
201.5	71.43	1230.22	17.22	241780	0.0333
240.5	92.49	1285.60	13.90	288598	0.0393
283.9	106.92	1299.10	12.15	340739	0.0460
319.7	124.32	1293.96	10.41	383611	0.0518
360.3	182.41	1582.91	8.68	432352	0.0599
399.2	281.92	1796.82	6.37	479072	0.0731
437.8	358.56	1501.81	4.19	525347	0.0902
479.5	524.17	1339.84	2.56	575374	0.1147
519.3	720.12	1417.76	1.97	623202	0.1483
557.8	737.30	1316.03	1.78	669347	0.1800
597.1	777.80	1219.63	1.57	716472	0.2098
637.6	863.08	1087.38	1.26	765115	0.2402
681.4	969.37	1146.21	1.18	817738	0.2743
719.4	1096.35	1286.48	1.17	863308	0.3052
759.3	1154.36	1241.38	1.08	911195	0.3395
780.8	1184.55	1298.50	1.10	936935	0.3566

Table: C.5
Simulation Results For Run ABR5 5 Bottom Water
(ABERFELDY)

Legend:

T : Time, Days
 OPR : Oil Production Rate, Bbls/Day
 WPR : Water Production Rate, Bbls/Day
 WOR : Cumulative Water-Oil Ratio, Bbl/Bbl
 CSI : Cumulative Steam Injected, Bbls
 OSR : Cumulative Oil-Steam Ratio, Bbl/Bbl

T	OPR	WPR	WOR	CSI	OSR
37.6	9.38	102.26	10.90	22554	0.0157
75.1	9.37	174.84	18.66	45074	0.0157
107.4	12.78	263.19	20.59	64421	0.0168
138.9	15.82	341.47	21.58	83349	0.0186
177.6	19.25	427.93	22.23	106553	0.0211
209.5	22.04	491.06	22.28	125685	0.0233
248.2	25.70	558.66	21.74	148905	0.0261
288.2	30.33	620.33	20.45	172905	0.0292
315.9	34.44	659.43	19.14	189535	0.0315
347.2	41.04	710.97	17.32	208309	0.0344
387.8	55.19	768.41	13.92	232697	0.0394
423.7	61.00	806.97	13.23	254250	0.0445
461.8	65.90	839.68	12.74	277065	0.0496
485.7	69.70	860.74	12.35	291414	0.0528
528.8	78.73	901.05	11.44	317291	0.0587
560.2	87.93	931.53	10.59	336105	0.0633
596.0	136.33	1384.36	10.15	357590	0.0704
630.3	192.01	1595.79	8.31	378176	0.0815
664.7	261.02	1474.04	5.65	398817	0.0969
689.2	450.65	1635.21	3.63	413546	0.1134

Table: C.6
Simulation Results For Run ABRS 6 **Bottom Water**
(ABERFELDY)

Legend:

T : Time, Days
 OPR : Oil Production Rate, Bbls/Day
 WPR : Water Production Rate, Bbls/Day
 WOR : Cumulative Water-Oil Ratio, Bbl/Bbl
 CSI : Cumulative Steam Injected, Bbls
 OSR : Cumulative Oil-Steam Ratio, Bbl/Bbl

T	OPR	WPR	WOR	CSI	OSR
24.3	9.46	104.68	11.07	14611	0.0158
54.1	9.43	137.75	14.60	32470	0.0158
80.3	10.08	193.87	19.23	48172	0.0159
102.7	13.10	265.75	20.28	61640	0.0169
121.4	15.22	317.08	20.83	72853	0.0181
153.8	18.78	400.47	21.30	92267	0.0204
179.5	21.69	461.34	21.27	107715	0.0225
194.2	23.46	493.82	21.05	116501	0.0238
228.5	28.26	564.48	19.97	137097	0.0270
248.5	31.81	602.74	18.95	149097	0.0290
268.5	36.30	639.48	17.62	161097	0.0314
299.2	46.11	691.95	15.00	179549	0.0356
323.7	57.67	736.75	12.77	194233	0.0395
353.5	62.66	779.57	12.44	212103	0.0447
374.3	66.78	809.13	12.11	224581	0.0483
399.4	72.82	843.46	11.58	239657	0.0527
423.0	80.00	876.86	10.96	253829	0.0571
448.8	90.04	912.44	10.13	269290	0.0620
475.6	103.73	936.48	9.03	285383	0.0677
500.1	163.04	1361.15	8.35	300072	0.0751
525.2	246.88	1602.98	6.49	315107	0.0878

Table: C.7
Simulation Results For Run ABRS 7 Bottom Water
(ABERFELDY)

Legend:

T : Time, Days
 OPR : Oil Production Rate, Bbls/Day
 WPR : Water Production Rate, Bbls/Day
 WOR : Cumulative Water-Oil Ratio, Bbl/Bbl
 CSI : Cumulative Steam Injected, Bbls
 OSR : Cumulative Oil-Steam Ratio, Bbl/Bbl

T	OPR	WPR	WOR	CSI	OSR
39.1	9.35	98.54	10.54	23468	0.0157
78.0	9.32	174.93	18.76	46827	0.0156
122.3	13.60	287.50	21.14	73397	0.0172
157.9	16.63	368.54	22.18	94739	0.0192
202.6	20.04	457.92	22.85	121576	0.0219
240.6	22.86	532.09	22.88	144385	0.0243
280.6	26.03	582.64	22.38	168385	0.0268
320.6	29.77	634.59	21.32	192385	0.0295
360.4	34.46	680.37	19.75	216222	0.0322
397.0	42.29	760.87	17.99	238233	0.0353
435.9	52.75	795.96	15.09	261525	0.0393
479.5	60.05	826.17	13.76	287715	0.0446
519.3	63.75	853.25	13.38	311562	0.0491
559.0	68.55	881.23	12.86	335407	0.0535
599.8	75.10	910.64	12.13	359888	0.0581
640.7	88.87	1009.91	11.36	384428	0.0629
679.8	130.50	1402.22	10.75	407867	0.0699
719.7	169.37	1494.25	8.82	431830	0.0799
760.5	214.39	1348.68	6.29	456314	0.0928

Table: C.8
Simulation Results For Run ABR8 8 (No Bottom Water)
(ABERFELDY)

Legend:

T : Time, Days
 OPR : Oil Production Rate, Bbls/Day
 WPR : Water Production Rate, Bbls/Day
 WOR : Cumulative Water-Oil Ratio, Bbl/Bbl
 CSI : Cumulative Steam Injected, Bbls
 OSR : Cumulative Oil-Steam Ratio, Bbl/Bbl

T	OPR	WPR	WOR	CSI	OSR
38.5	33.52	461.44	13.77	46160	0.0216
79.5	47.18	826.17	17.51	95440	0.0284
117.1	57.06	1027.66	18.01	140531	0.0335
159.8	69.98	1148.05	16.40	191828	0.0389
199.0	88.09	1199.65	13.62	238788	0.0442
238.9	115.56	1231.61	10.66	286652	0.0514
276.7	132.21	1237.83	9.36	332011	0.0586
320.8	159.86	1224.63	7.66	385019	0.0675
355.1	195.73	1172.44	5.99	426088	0.0757
400.0	305.45	1414.04	4.63	479954	0.0900
440.0	458.05	1755.07	3.83	528015	0.1110
481.4	693.93	1631.70	2.35	577728	0.1420
519.1	841.99	1517.09	1.80	622967	0.1816
563.1	845.10	1322.64	1.56	675732	0.2222
600.4	873.02	1223.21	1.40	720464	0.2529
637.8	938.16	1086.45	1.16	765406	0.2825
680.1	1035.87	1143.88	1.10	816144	0.3163
719.2	1143.53	1263.57	1.10	863073	0.3487
762.3	1193.13	1236.52	1.04	914810	0.8351

Table: C.9
Simulation Results For Run ABR5 9 Bottom Water
(ABERFELDY)

Legend:

T : Time, Days
 OPR : Oil Production Rate, Bbls/Day
 WPR : Water Production Rate, Bbls/Day
 WOR : Cumulative Water-Oil Ratio, Bbl/Bbl
 CSI : Cumulative Steam Injected, Bbls
 OSR : Cumulative Oil-Steam Ratio, Bbl/Bbl

T	OPR	WPR	WOR	CSI	OSR
23.0	9.46	105.19	11.12	13816	0.0159
54.2	9.44	135.75	14.39	32504	0.0158
80.5	9.86	188.56	19.12	48317	0.0159
103.0	12.87	259.55	20.16	61787	0.0168
121.7	15.00	310.63	20.71	73047	0.0179
154.3	18.59	394.03	21.19	92580	0.0202
180.2	21.55	455.21	21.12	108114	0.0223
194.9	23.35	487.96	20.89	116927	0.0236
224.9	27.55	552.25	20.04	134916	0.0262
247.0	31.58	602.73	19.08	148235	0.0283
273.0	37.70	656.80	17.42	163807	0.0312
294.8	44.86	697.72	15.56	176869	0.0341
326.9	59.05	755.42	12.79	196142	0.0399
343.8	61.92	779.88	12.59	206292	0.0430
373.8	67.87	822.75	12.12	224306	0.0484
402.1	75.06	864.50	11.52	241293	0.0536
427.6	83.34	902.16	10.83	256558	0.0584
451.2	93.34	936.68	10.04	270706	0.0631
475.6	110.95	1010.19	9.11	285386	0.0686
500.5	181.22	1497.22	8.26	300324	0.0772

Table: C.10
Simulation Results For Run ABRS 11 (No Bottom Water)
(ABERFELDY)

Legend:

T : Time, Days
 OPR : Oil Production Rate, Bbls/Day
 WPR : Water Production Rate, Bbls/Day
 WOR : Cumulative Water-Oil Ratio, Bbl/Bbl
 CSI : Cumulative Steam Injected, Bbls
 OSR : Cumulative Oil-Steam Ratio, Bbl/Bbl

T	OPR	WPR	WOR	CSI	OSR
48.9	192.67	236.69	1.23	29347	0.3245
99.3	199.89	279.02	1.40	59577	0.3256
151.8	220.97	316.52	1.43	91108	0.3337
199.5	261.05	343.80	1.32	119725	0.3499
247.5	363.72	387.90	1.07	148533	0.3833
304.0	404.21	402.71	1.00	182414	0.4317
344.9	435.64	402.01	0.92	206922	0.4642
393.3	479.66	404.99	0.84	236013	0.5020
452.7	676.84	520.53	0.77	271605	0.5557
500.7	1152.53	841.73	0.73	300423	0.6478
550.5	1362.02	1001.65	0.74	330313	0.7903
599.5	792.25	621.85	0.78	359686	0.8643
649.1	566.81	472.01	0.83	389440	0.8835
701.1	512.01	439.67	0.86	420679	0.8829
749.4	535.22	449.78	0.84	449664	0.8819
802.6	760.10	534.26	0.70	481570	0.8943
848.5	1652.37	774.77	0.47	509115	0.9497
899.9	2364.58	1648.22	0.70	539967	1.1058
940.1	2749.35	1889.44	0.69	564061	1.2382

Table: C.11
Simulation Results For Run ABR514 (No Bottom Water)
(ABERFELDY)

Legend:

T : Time, Days
 OPR : Oil Production Rate, Bbls/Day
 WPR : Water Production Rate, Bbls/Day
 WOR : Cumulative Water-Oil Ratio, Bbl/Bbl
 CSI : Cumulative Steam Injected, Bbls
 OSR : Cumulative Oil-Steam Ratio, Bbl/Bbl

T	OPR	WPR	WOR	CSI	OSR
50.4	38.75	583.59	15.06	60456	0.0321
97.2	52.21	997.71	19.11	116623	0.0341
150.7	69.36	1223.28	17.64	180877	0.0403
198.5	90.99	1269.04	13.95	238179	0.0467
247.6	127.97	1280.89	10.01	297137	0.0560
300.4	172.30	1427.97	8.29	360446	0.0675
349.2	306.70	1861.59	6.07	419084	0.0859
397.0	433.40	1294.37	2.99	476394	0.1129
450.4	594.98	1185.37	1.99	540470	0.1514
499.2	886.99	1418.08	1.60	599095	0.1963
548.4	873.58	1344.27	1.54	658129	0.2481
603.2	855.08	1089.07	1.27	723979	0.2897
648.8	910.27	1056.50	1.16	778572	0.3215
700.0	943.83	1149.52	1.22	840023	0.3551
750.9	967.33	1137.50	1.18	901116	0.3849
800.4	2068.99	2563.11	1.24	960520	0.4319
850.9	2316.46	2453.75	1.06	1021036	0.5125
900.4	2166.26	2289.75	1.06	1080465	0.5989
949.8	1826.86	1694.96	0.93	1139819	0.6511
1000.4	1982.62	1667.34	0.84	1200529	0.6999
1050.1	3650.68	2456.51	0.67	1260107	0.7530

Table: C.12
Simulation Results For Run ABR516
(ABERFELDY)

Bottom Water

Legend:

T : Time, Days

OPR : Oil Production Rate, Bbls/Day

WPR : Water Production Rate, Bbls/Day

WOR : Cumulative Water-Oil Ratio, Bbl/Bbl

CSI : Cumulative Steam Injected, Bbls

OSR : Cumulative Oil-Steam Ratio, Bbl/Bbl

T	OPR	WPR	WOR	CSI	OSR
32.6	9.38	97.79	10.42	19593	0.0158
56.5	9.38	137.23	14.63	33905	0.0157
93.6	11.35	227.63	20.05	56157	0.0161
122.1	14.26	301.31	21.13	73256	0.0175
144.4	16.34	355.25	21.74	86656	0.0189
184.6	19.86	443.32	22.32	110739	0.0216
218.0	22.79	507.85	22.28	130796	0.0239
237.8	24.64	542.57	22.02	142681	0.0253
277.8	28.94	606.34	20.95	166681	0.0283
297.8	31.57	635.48	20.13	178681	0.0300
330.9	37.12	683.52	18.41	198548	0.0328
361.1	45.51	750.68	16.50	216674	0.0360
393.2	58.03	788.86	13.59	235930	0.0402
420.2	60.71	812.49	13.38	252132	0.0440
450.1	64.33	840.27	13.06	270049	0.0480
478.7	68.58	867.79	12.65	287209	0.0518
512.2	74.89	900.63	12.02	307298	0.0563
540.6	81.77	927.24	11.34	324358	0.0602
570.7	94.80	1001.53	10.56	342396	0.0647
600.7	139.85	1397.79	9.99	360433	0.0713
630.1	186.54	1572.08	8.43	378071	0.0807
658.7	229.42	1455.15	6.34	395205	0.0922

Table: C.13
Simulation Results For Run ABR516 **Bottom Water**
(ABERFELDY)

Legend:

T : Time, Days
 OPR : Oil Production Rate, Bbls/Day
 WPR : Water Production Rate, Bbls/Day
 WOR : Cumulative Water-Oil Ratio, Bbl/Bbl
 CSI : Cumulative Steam Injected, Bbls
 OSR : Cumulative Oil-Steam Ratio, Bbl/Bbl

T	OPR	WPR	WOR	CSI	OSR
33.5	91.16	103.97	1.14	20134	0.1546
75.0	90.96	170.07	1.87	44992	0.1530
103.3	104.11	221.47	2.13	61968	0.1559
141.7	134.84	308.55	2.29	85004	0.1703
176.9	157.81	377.32	2.39	106129	0.1863
210.3	177.50	433.18	2.44	126181	0.2020
242.6	196.19	478.62	2.44	145545	0.2172
282.6	221.56	523.47	2.36	169557	0.2364
313.8	245.47	548.38	2.23	188261	0.2520
352.0	284.51	571.19	2.01	211228	0.2731
387.9	340.46	588.76	1.73	232725	0.2968
421.5	387.35	608.98	1.57	252887	0.3232
454.4	390.92	611.22	1.56	272634	0.3467
490.0	403.72	615.62	1.52	294025	0.3693
524.8	587.19	899.95	1.53	314879	0.3997
560.2	798.56	1125.00	1.41	336107	0.4483
595.5	910.61	1093.48	1.20	357277	0.5073
630.7	951.10	959.37	1.01	378428	0.5660
666.3	916.78	734.87	0.80	399766	0.6176

Table: C.14
Simulation Results For Cyclic Run ABC 1 (No Bottom Water)
(ABERFELDY)

Legend:

T : Time, Days
OPR : Oil Production Rate, Bbls/Day
WPR : Water Production Rate, Bbls/Day
WOR : Cumulative Water-Oil Ratio, Bbl/Bbl
CSI : Cumulative Steam Injected, Bbls
OSR : Cumulative Oil-Steam Ratio, Bbl/Bbl

T	OPR	WPR	WOR	CSI	OSR

Cycle 1					
35.1	80.53	473.74	5.88	21000	0.0003
44.2	39.69	197.34	4.97	21000	0.0203
53.5	37.02	179.33	4.84	21000	0.0369
68.1	32.95	161.10	4.89	21000	0.0605
76.3	30.80	152.43	4.95	21000	0.0725
85.1	19.99	134.59	6.73	21000	0.0808
94.5	14.91	121.64	8.16	21000	0.0875
105.1	11.96	109.51	9.15	21000	0.0936
117.4	9.92	98.05	9.88	21000	0.0994
125.0	9.10	92.58	10.18	21000	0.1027

Table: C.15
Simulation Results For Cyclic Run ABC 2 (No Bottom Water)
(ABERFELDY)

Legend:

T : Time, Days
 OPR : Oil Production Rate, Bbls/Day
 WPR : Water Production Rate, Bbls/Day
 WOR : Cumulative Water-Oil Ratio, Bbl/Bbl
 CSI : Cumulative Steam Injected, Bbls
 OSR : Cumulative Oil-Steam Ratio, Bbl/Bbl

T	OPR	WPR	WOR	CSI	OSR

Cycle 1					
35.1	86.38	312.73	3.62	18000	0.0006
46.5	47.11	162.83	3.46	18000	0.0338
59.0	41.16	153.87	3.74	18000	0.0634
75.4	34.78	142.83	4.11	18000	0.0964
84.3	31.90	136.65	4.28	18000	0.1122
93.9	27.75	128.99	4.65	18000	0.1270
104.2	17.22	113.59	6.59	18000	0.1368
115.3	13.03	103.10	7.91	18000	0.1449
125.0	11.03	95.41	8.65	18000	0.1508
Cycle 2					
170.2	62.52	297.34	4.76	42000	0.0649
180.1	21.12	330.67	15.65	42000	0.0746
190.0	7.04	376.25	53.41	42000	0.0775
200.3	9.53	482.61	50.62	42000	0.0797
210.3	8.05	387.97	48.16	42000	0.0818
221.7	4.97	301.72	60.69	42000	0.0836
229.4	3.67	260.38	70.95	42000	0.0843
242.3	2.64	202.88	76.88	42000	0.0852
250.2	2.30	177.67	77.34	42000	0.0857
260.0	2.00	153.94	76.87	42000	0.0861
Cycle 3					
315.0	49.48	769.49	15.55	72000	0.0503
322.5	26.83	572.61	21.34	72000	0.0528

Table: C.16
Simulation Results For Cyclic Run ABC 3 (No Bottom Water)
(ABERFELDY)

Legend:

T : Time, Days
 OPR : Oil Production Rate, Bbls/Day
 WPR : Water Production Rate, Bbls/Day
 WOR : Cumulative Water-Oil Ratio, Bbl/Bbl
 CSI : Cumulative Steam Injected, Bbls
 OSR : Cumulative Oil-Steam Ratio, Bbl/Bbl

T	OPR	WPR	WOR	CSI	OSR

Cycle 1					
35.1	86.38	312.73	3.62	18000	0.0006
46.5	47.11	162.83	3.46	18000	0.0338
59.0	41.16	153.87	3.74	18000	0.0634
67.0	37.87	148.56	3.92	18000	0.0801
75.4	34.78	142.83	4.11	18000	0.0964
84.3	31.90	136.65	4.28	18000	0.1122
93.9	27.75	128.99	4.65	18000	0.1270
104.2	17.22	113.59	6.60	18000	0.1368
115.3	13.03	103.10	7.91	18000	0.1449
125.0	11.03	95.41	8.65	18000	0.1508
Cycle 2					
150.0	78.50	509.26	6.49	30000	0.0905
160.2	32.58	197.72	6.07	30000	0.1061
170.1	12.52	180.14	14.38	30000	0.1134
180.2	9.86	257.05	26.06	30000	0.1164
191.5	9.80	234.15	23.88	30000	0.1202
200.0	9.18	207.64	22.63	30000	0.1228
209.7	8.60	182.39	21.21	30000	0.1257
221.1	6.85	150.87	22.03	30000	0.1285
227.7	5.74	138.11	24.05	30000	0.1298
240.0	4.57	119.84	26.19	30000	0.1317
Cycle 3					
255.2	20.47	379.95	18.56	36000	0.1099
265.3	11.10	187.70	16.91	36000	0.1136
275.4	7.51	148.48	19.76	36000	0.1162
285.1	5.75	131.32	22.83	36000	0.1179
294.2	6.39	147.20	23.04	36000	0.1194
309.2	5.00	126.38	25.29	36000	0.1217
324.0	3.89	107.50	27.64	36000	0.1234
332.0	3.53	98.03	27.79	36000	0.1242
345.0	3.16	87.37	27.62	36000	0.1254

Table: C.17
Simulation Results For Cyclic Run ABC 4 (No Bottom Water)
(ABERFELDY)

Legend:

T : Time, Days
 OPR : Oil Production Rate, Bbls/Day
 WPR : Water Production Rate, Bbls/Day
 WOR : Cumulative Water-Oil Ratio, Bbl/Bbl
 CSI : Cumulative Steam Injected, Bbls
 OSR : Cumulative Oil-Steam Ratio, Bbl/Bbl

T	OPR	WPR	WOR	CSI	OSR

Cycle 1					
50.1	74.37	291.63	3.92	18000	0.0005
63.1	44.05	164.83	3.74	18000	0.0350
69.4	41.55	159.44	3.84	18000	0.0496
85.5	35.75	147.22	4.12	18000	0.0827
94.2	33.01	140.78	4.26	18000	0.0988
103.6	27.51	131.77	4.79	18000	0.1131
113.7	17.82	116.94	6.56	18000	0.1231
124.7	13.67	106.25	7.77	18000	0.1315
140.0	10.79	94.48	8.75	18000	0.1408
Cycle 2					
190.2	53.52	627.32	11.72	36000	0.0707
200.0	32.82	344.70	10.50	36000	0.0816
210.0	11.62	291.76	25.11	36000	0.0874

Table: C.18
Simulation Results For Cyclic Run ABC 6 (Bottom Water)
(ABERFELDY)

Legend:

T : Time, Days
OPR : Oil Production Rate, Bbls/Day
WPR : Water Production Rate, Bbls/Day
WOR : Cumulative Water-Oil Ratio, Bbl/Bbl
CSI : Cumulative Steam Injected, Bbls
OSR : Cumulative Oil-Steam Ratio, Bbl/Bbl

T	OPR	WPR	WOR	CSI	OSR

Cycle 1					
35.1	36.37	688.31	18.92	18000	0.0002
46.6	25.92	307.03	11.85	18000	0.0179
55.8	18.06	257.66	14.27	18000	0.0281
69.1	11.86	220.91	18.63	18000	0.0378
77.0	9.79	204.91	20.94	18000	0.0421
85.8	8.16	189.81	23.26	18000	0.0461
95.6	6.86	175.42	25.56	18000	0.0498
106.4	5.81	161.66	27.83	18000	0.0533
118.5	4.94	148.52	30.07	18000	0.0566
125.0	4.56	142.18	31.17	18000	0.0583
Cycle 2					
160.2	49.05	753.48	15.36	36000	0.0294
170.1	34.74	301.60	8.68	36000	0.0407
180.0	20.69	269.63	13.03	36000	0.0477
190.0	13.36	217.49	16.27	36000	0.0528
200.2	2.81	209.64	74.56	36000	0.0549
212.6	3.23	262.16	81.14	36000	0.0560
225.9	3.21	228.31	71.17	36000	0.0571
234.5	3.22	209.84	65.11	36000	0.0579
244.2	3.20	191.84	59.93	36000	0.0588
250.0	3.16	181.87	57.57	36000	0.0593
Cycle 3					
285.5	31.38	513.08	16.35	54000	0.0398
295.1	13.58	328.99	24.22	54000	0.0440

Table: C.19
Simulation Results For Cyclic Run ABC 8 (Bottom Water)
(ABERFELDY)

Legend:

T : Time, Days
 OPR : Oil Production Rate, Bbls/Day
 WPR : Water Production Rate, Bbls/Day
 WOR : Cumulative Water-Oil Ratio, Bbl/Bbl
 CSI : Cumulative Steam Injected, Bbls
 OSR : Cumulative Oil-Steam Ratio, Bbl/Bbl

T	OPR	WPR	WOR	CSI	OSR

Cycle 1					
35.1	36.37	688.31	18.92	18000	0.0002
46.6	25.92	307.03	11.85	18000	0.0179
55.8	18.06	257.66	14.27	18000	0.0281
69.1	11.86	220.91	18.63	18000	0.0378
77.0	9.79	204.91	20.94	18000	0.0421
85.8	8.16	189.81	23.26	18000	0.0461
95.6	6.86	175.42	25.56	18000	0.0498
106.4	5.81	161.66	27.83	18000	0.0533
118.5	4.94	148.52	30.07	18000	0.0566
125.0	4.56	142.18	31.17	18000	0.0583
Cycle 2					
150.0	30.91	619.62	20.04	30000	0.0351
160.2	20.68	346.31	16.74	30000	0.0426
174.9	17.73	251.64	14.19	30000	0.0517
181.9	16.48	231.03	14.01	30000	0.0555
189.9	15.19	212.61	14.00	30000	0.0596
198.9	13.90	195.64	14.08	30000	0.0638
209.1	12.64	179.83	14.23	30000	0.0681
220.7	11.42	165.04	14.44	30000	0.0725
234.0	10.28	151.26	14.71	30000	0.0770
240.0	9.82	145.13	14.77	30000	0.0790
Cycle 3					
255.2	17.38	388.90	22.38	36000	0.0659
265.1	13.07	253.49	19.39	36000	0.0698
277.4	11.43	203.85	17.83	36000	0.0739
287.2	10.73	181.80	16.95	36000	0.0769
299.6	9.88	162.78	16.47	36000	0.0804
310.6	9.18	149.71	16.31	36000	0.0832
327.2	7.81	131.43	16.82	36000	0.0870
337.5	7.36	126.45	17.17	36000	0.0891
345.0	7.00	119.83	17.11	36000	0.0906

Table: C.20
Simulation Results For Cyclic Run ABC 9 (Bottom Water)
(ABERFELDY)

Legend:

T : Time, Days
 OPR : Oil Production Rate, Bbls/Day
 WPR : Water Production Rate, Bbls/Day
 WOR : Cumulative Water-Oil Ratio, Bbl/Bbl
 CSI : Cumulative Steam Injected, Bbls
 OSR : Cumulative Oil-Steam Ratio, Bbl/Bbl

T	OPR	WPR	WOR	CSI	OSR

Cycle 1					
50.1	35.87	647.04	18.04	18000	0.0002
60.5	24.09	307.43	12.76	18000	0.0158
70.9	15.93	263.25	16.52	18000	0.0260
84.5	10.95	228.59	20.87	18000	0.0350
92.4	9.22	212.47	23.04	18000	0.0391
101.1	7.83	196.93	25.16	18000	0.0429
110.1	6.69	181.97	27.22	18000	0.0464
121.4	5.74	167.63	29.21	18000	0.0498
133.3	4.94	153.97	31.16	18000	0.0531
140.0	4.58	146.98	32.12	18000	0.0548
Cycle 2					
190.0	41.36	805.69	19.48	36000	0.0274
200.6	25.05	406.59	16.23	36000	0.0357
207.3	15.58	317.76	20.40	36000	0.0395

Table: C.21
Simulation Results For Cyclic Run ABC11 (Bottom Water)
(ABERFELDY)

Legend:

T : Time, Days
 OPR : Oil Production Rate, Bbls/Day
 WPR : Water Production Rate, Bbls/Day
 WOR : Cumulative Water-Oil Ratio, Bbl/Bbl
 CSI : Cumulative Steam Injected, Bbls
 OSR : Cumulative Oil-Steam Ratio, Bbl/Bbl

T	OPR	WPR	WOR	CSI	OSR

Cycle 1					
37.8	30.51	196.40	6.44	18000	0.0048
47.0	25.61	197.74	7.72	18000	0.0184
58.4	21.23	197.21	9.29	18000	0.0325
65.1	19.20	195.47	10.18	18000	0.0396
72.5	17.29	192.67	11.14	18000	0.0468
90.5	13.77	183.59	13.33	18000	0.0613
101.5	12.16	177.13	14.56	18000	0.0688
114.2	10.72	170.18	15.87	18000	0.0764
125.0	9.75	164.58	16.87	18000	0.0822
Cycle 2					
160.5	28.36	289.28	10.20	36000	0.0415
170.0	1.95	435.73	223.49	36000	0.0455
179.4	1.74	510.80	293.36	36000	0.0460
190.3	1.32	432.07	326.87	36000	0.0465
197.9	1.12	387.34	344.63	36000	0.0467
216.1	0.81	302.88	374.37	36000	0.0471
227.1	0.68	263.03	386.07	36000	0.0473
239.9	0.57	217.07	381.77	36000	0.0476
250.0	0.50	186.99	374.12	36000	0.0477

Table: C.22
Simulation Results For Cyclic Run ABC17 (Bottom Water)
(ABERFELDY)

Legend:

T : Time, Days
 OPR : Oil Production Rate, Bbls/Day
 WPR : Water Production Rate, Bbls/Day
 WOR : Cumulative Water-Oil Ratio, Bbl/Bbl
 CSI : Cumulative Steam Injected, Bbls
 OSR : Cumulative Oil-Steam Ratio, Bbl/Bbl

T	OPR	WPR	WOR	CSI	OSR

Cycle 1					
36.8	30.19	201.54	6.67	18000	0.0030
48.1	24.38	200.93	8.24	18000	0.0194
54.1	22.11	199.98	9.04	18000	0.0268
68.5	17.92	194.75	10.87	18000	0.0419
77.2	16.00	190.29	11.89	18000	0.0496
87.2	14.18	184.46	13.01	18000	0.0575
99.0	12.46	177.15	14.21	18000	0.0656
112.9	10.84	168.18	15.52	18000	0.0740
125.0	9.75	161.13	16.53	18000	0.0806
Cycle 2					
160.7	29.67	292.63	9.86	36000	0.0409
170.0	21.00	316.48	15.07	36000	0.0472
179.6	3.58	451.36	125.99	36000	0.0493
191.3	2.91	387.27	133.17	36000	0.0503
199.6	2.60	350.67	134.78	36000	0.0509
208.8	2.34	316.10	135.17	36000	0.0515
219.0	2.09	282.80	135.30	36000	0.0521
230.6	1.87	251.27	134.65	36000	0.0527
243.8	1.66	221.38	133.44	36000	0.0533
250.0	1.57	208.57	132.79	36000	0.0536
Cycle 3					
286.7	14.88	331.36	22.26	54000	0.0362
298.0	2.94	372.76	126.67	54000	0.0382

Table: C.23
Cyclic Run CLC1A (No Bottom Water)
(COLD LAKE)

Legend:

T : Time, Days
 OPR : Oil Production Rate, Bbls/Day
 WPR : Water Production Rate, Bbls/Day
 WOR : Cumulative Water-Oil Ratio, Bbl/Bbl
 CSI : Cumulative Steam Injected, Bbls
 OSR : Cumulative Oil-Steam Ratio, Bbl/Bbl

T	OPR	WPR	WOR	CSI	OSR

Cycle 1					
35.8	16.87	72.22	4.28	18000	0.0008
46.0	9.59	42.27	4.40	18000	0.0078
55.9	5.87	25.93	4.42	18000	0.0118
64.5	3.75	17.02	4.54	18000	0.0139
71.8	3.16	14.11	4.47	18000	0.0153
84.0	2.24	9.93	4.44	18000	0.0169
94.9	1.69	7.98	4.73	18000	0.0180
106.7	1.31	6.99	5.32	18000	0.0189
113.4	1.19	6.42	5.41	18000	0.0194
125.0	0.84	5.28	6.25	18000	0.0199
Cycle 2					
160.2	21.17	330.79	15.62	36000	0.0101
170.5	13.86	127.92	9.23	36000	0.0152
179.8	8.22	77.32	9.41	36000	0.0179
189.2	4.50	54.31	12.06	36000	0.0194
199.6	2.58	41.39	16.04	36000	0.0203
210.1	1.55	31.76	20.52	36000	0.0208
220.0	1.14	26.60	23.31	36000	0.0212
231.9	0.78	20.12	25.71	36000	0.0215
239.7	0.67	17.75	26.37	36000	0.0216
250.0	0.51	13.73	26.77	36000	0.0218
Cycle 3					
285.2	1.72	573.97	333.39	54000	0.0145
295.0	0.55	189.02	346.61	54000	0.0147

Table: C.24
Cyclic Run CLC6A (Bottom Water) 36FT/36 FT
(COLD LAKE)

Legend:

T : Time, Days
OPR : Oil Production Rate, Bbls/Day
WPR : Water Production Rate, Bbls/Day
WOR : Cumulative Water-Oil Ratio, Bbl/Bbl
CSI : Cumulative Steam Injected, Bbls
OSR : Cumulative Oil-Steam Ratio, 10^{-3} Bbl/Bbl

T	OPR	WPR	WOR	CSI	OSR

Cycle 1					
35.2	0.06	100.46	1814.86	18000	0.0005
43.7	0.05	67.67	1344.86	18000	0.0253
52.5	0.05	53.89	1146.04	18000	0.0486
68.4	0.04	46.39	1115.95	18000	0.0865
82.4	0.04	44.10	1174.04	18000	0.1157
102.4	0.03	42.90	1290.09	18000	0.1526
125.0	0.03	43.02	1441.68	18000	0.1905

Table: C.25
Cyclic Run CLC11A (Bottom Water) 36FT/36FT
(COLD LAKE)

Legend:

T : Time, Days
OPR : Oil Production Rate, Bbls/Day
WPR : Water Production Rate, Bbls/Day
WOR : Cumulative Water-Oil Ratio, Bbl/Bbl
CSI : Cumulative Steam Injected, Bbls
OSR : Cumulative Oil-Steam Ratio, 10^{-3} Bbl/Bbl

T	OPR	WPR	WOR	CSI	OSR

Cycle 1					
36.0	0.54	51.79	95.97	18000	0.0313
48.7	0.47	49.30	104.87	18000	0.3790
56.7	0.44	48.26	110.42	18000	0.5713
68.5	0.40	46.92	118.30	18000	0.8330
86.3	0.35	45.24	128.75	18000	1.1807
106.3	0.31	43.71	140.29	18000	1.5270
125.0	0.20	39.19	197.77	18000	1.7320
Cycle 2					
160.1	0.89	36.56	41.26	36000	0.8696
163.4	0.03	90.82	3619.71	36000	0.9105

Table: C.26
 BOTTOM WATER (36FT/36FT) STEAMFLOOD; ABERFELDY RUN ABR2A
 INJ. OVER ENTIRE INTERVAL; MOBILE OIL (50%) IN BW ZONE
 INJ. RATE 600 BBLS/DAY

Legend:

T : Time, Days
 OPR : Oil Production Rate, Bbls/Day
 WPR : Water Production Rate, Bbls/Day
 WOR : Cumulative Water-Oil Ratio, Bbl/Bbl
 CSI : Cumulative Steam Injected, 10³ Bbls
 ORec : Oil Recovery, %
 OSR : Cumulative Oil-Steam Ratio, Bbl/Bbl

T	OPR	WPR	WOR	CSI	ORec	OSR
47	13.8	168	12.20	0.283	0.03	0.0204
102	17.4	260	14.90	0.612	0.07	0.0239
152	20.0	340	17.00	0.911	0.11	0.0266
211	22.6	424	18.70	1.265	0.17	0.0293
251	24.3	471	19.40	1.504	0.21	0.0310
311	26.6	532	20.00	1.865	0.28	0.0333
351	28.1	567	20.20	2.105	0.33	0.0348
411	30.2	612	20.30	2.465	0.41	0.0369
451	31.7	638	20.10	2.705	0.47	0.0382
511	34.2	671	19.60	3.065	0.56	0.0403
551	36.1	690	19.10	3.305	0.62	0.0416
611	39.5	713	18.10	3.665	0.72	0.0438
651	42.4	728	17.20	3.905	0.80	0.0454
701	47.5	756	15.90	4.204	0.90	0.0476
754	56.8	822	14.50	4.522	1.03	0.0504
799	64.5	836	13.00	4.795	1.15	0.0534
849	64.6	826	12.80	5.094	1.30	0.0566
899	65.4	824	12.60	5.393	1.44	0.0594
959	67.4	830	12.30	5.753	1.62	0.0627
999	68.5	825	12.00	5.993	1.75	0.0647
1059	71.2	823	11.60	6.353	1.94	0.0677
1100	73.7	822	11.20	6.600	2.07	0.0697

Table: C.27
 PARTIAL PENETRATION STEAMFLOOD: ABERFELDY RUN ABRS1B; NO
 BOTTOM WATER
 INJ. RATE 600 BBL/DAY; INJ. OVER LOWER ONE-HALF INTERVAL

Legend:

T : Time, Days
 OPR : Oil Production Rate, Bbls/Day
 WPR : Water Production Rate, Bbls/Day
 WOR : Cumulative Water-Oil Ratio, Bbl/Bbl
 CSI : Cumulative Steam Injected, 10^5 Bbls
 ORec : Oil Recovery, %
 OSR : Cumulative Oil-Steam Ratio, Bbl/Bbl

T	OPR	WPR	WOR	CSI	ORec	OSR
51	16.6	204	12.20	0.308	0.05	0.0277
108	17.2	298	17.30	0.646	0.11	0.0279
152	22.2	428	19.30	0.910	0.16	0.0294
212	28.4	543	19.10	1.272	0.25	0.0335
252	32.2	588	18.30	1.512	0.33	0.0363
304	37.8	621	16.40	1.823	0.44	0.0402
344	43.8	632	14.40	2.067	0.54	0.0436
413	61.0	641	10.50	2.479	0.75	0.0509
462	82.1	645	7.86	2.773	0.97	0.0586
518	95.1	642	6.74	3.111	1.28	0.0687
551	103.0	639	6.21	3.305	1.47	0.0745
610	129.0	690	5.35	3.658	1.88	0.0863
666	154.0	643	4.16	3.996	2.37	0.0995
701	184.0	683	3.70	4.205	2.72	0.1084
754	262.0	828	3.15	4.522	3.43	0.1270
804	336.0	778	2.32	4.823	4.33	0.1500
847	432.0	775	1.79	5.083	5.32	0.1750
901	668.0	821	1.23	5.406	7.08	0.2190
948	730.0	802	1.10	5.686	9.14	0.2690
1009	666.0	703	1.06	6.055	11.68	0.3230
1058	655.0	682	1.04	6.346	13.58	0.3580
1100	640.0	662	1.03	6.600	15.22	0.3860

APPENDIX D
TABULATED DATA FOR WELLBORE HEAT LOSS

Table: D.1
STEAM QUALITY VS. DEPTH FOR DIFFERENT
RATES AND ZERO AND ONE-HALF STEAM
OFF-TAKE AT 1200 FT DEPTH; TIME = 100 DAYS
INJ. PRESS. 1500PSIA

Legend:

D : Depth, FT
 N O-T : No Off-Take
 H O-T : Half Off-Take

Steam Quality, Fraction

D	600 Bbls/Day		1200 Bbls/Day		1800 Bbls/Day	
	N O-T	H O-T	N O-T	H O-T	H O-T	N O-T
0	0.8000	0.8000	0.8000	0.8000	0.8000	0.8000
150	0.7718	0.7718	0.7858	0.7858	0.7904	0.7940
300	0.7435	0.7435	0.7715	0.7715	0.7809	0.7809
450	0.7151	0.7151	0.7573	0.7573	0.7713	0.7713
600	0.6864	0.6864	0.7429	0.7429	0.7617	0.7617
750	0.6574	0.6574	0.7285	0.7285	0.7521	0.7521
900	0.6283	0.6283	0.7140	0.7140	0.7424	0.7424
1050	0.5989	0.5705	0.6995	0.6854	0.7327	0.7234
1200	0.5693	0.5120	0.6849	0.6566	0.7230	0.7042
1350	0.5394	0.4530	0.6702	0.6275	0.7132	0.6850
1500	0.4779	0.3298	0.6402	0.5674	0.6934	0.6453

Table: D.2
STEAM QUALITY VS. DEPTH FOR DIFFERENT
RATES AND ZERO AND ONE-HALF STEAM
OFF-TAKE AT 1200 FT DEPTH; TIME = 300 DAYS
INJ. PRESS. 1500PSIA

Legend:

D : Depth, FT
 N O-T : No Off-Take
 H O-T : Half Off-Take

Steam Quality, Fraction

D	600 Bbls/Day		1200 Bbls/Day		1800 Bbls/Day	
	N O-T	H O-T	N O-T	H O-T	H O-T	N O-T
0	0.8000	0.8000	0.8000	0.8000	0.8000	0.8000
150	0.7731	0.7731	0.7864	0.7864	0.7909	0.7909
300	0.7461	0.7461	0.7728	0.7728	0.7817	0.7817
450	0.7188	0.7188	0.7592	0.7592	0.7726	0.7726
600	0.6914	0.6914	0.7454	0.7454	0.7634	0.7634
750	0.6638	0.6638	0.7317	0.7317	0.7542	0.7542
900	0.6360	0.6360	0.7178	0.7178	0.7449	0.7449
1050	0.6079	0.5808	0.7039	0.6905	0.7357	0.7267
1200	0.5796	0.5250	0.6900	0.6629	0.7264	0.7085
1350	0.5511	0.4685	0.6759	0.6352	0.7170	0.6901
1500	0.4897	0.3454	0.6460	0.5751	0.6972	0.6505

Table: D.3
STEAM QUALITY VS. DEPTH FOR DIFFERENT
RATES AND ZERO AND ONE-HALF STEAM
OFF-TAKE AT 1200 FT DEPTH; TIME = 500 DAYS
INJ. PRESS. 1500PSIA

Legend:

D : Depth, FT
 N O-T : No Off-Take
 H O-T : Half Off-Take

Steam Quality, Fraction

D	600 Bbls/Day		1200 Bbls/Day		1800 Bbls/Day	
	N O-T	H O-T	N O-T	H O-T	H O-T	N O-T
0	0.8000	0.8000	0.8000	0.8000	0.8000	0.8000
150	0.7731	0.7731	0.7864	0.7864	0.7909	0.7909
300	0.7461	0.7461	0.7728	0.7728	0.7817	0.7817
450	0.7189	0.7189	0.7592	0.7592	0.7726	0.7726
600	0.6916	0.6916	0.7455	0.7455	0.7634	0.7634
750	0.6640	0.6640	0.7317	0.7317	0.7542	0.7542
900	0.6362	0.6362	0.7179	0.7179	0.7450	0.7450
1050	0.6081	0.5810	0.7040	0.6906	0.7357	0.7268
1200	0.5799	0.5253	0.6901	0.6631	0.7265	0.7086
1350	0.5514	0.4689	0.6761	0.6353	0.7171	0.6902
1500	0.4900	0.3458	0.6461	0.5753	0.6973	0.6506

Table: D.4
STEAM QUALITY VS. DEPTH FOR DIFFERENT
RATES AND ZERO AND ONE-HALF STEAM
OFF-TAKE AT 1200 FT DEPTH; TIME = 700 DAYS
INJ. PRESS. 1500PSIA

Legend:

D : Depth, FT
 N O-T : No Off-Take
 H O-T : Half Off-Take

Steam Quality, Fraction

D	600 Bbls/Day		1200 Bbls/Day		1800 Bbls/Day	
	N O-T	H O-T	N O-T	H O-T	H O-T	N O-T
0	0.8000	0.8000	0.8000	0.8000	0.8000	0.8000
150	0.7731	0.7731	0.7864	0.7864	0.7909	0.7909
300	0.7461	0.7461	0.7728	0.7728	0.7817	0.7817
450	0.7189	0.7189	0.7592	0.7592	0.7726	0.7726
600	0.6916	0.6916	0.7455	0.7455	0.7634	0.7634
750	0.6640	0.6640	0.7317	0.7317	0.7542	0.7542
900	0.6362	0.6362	0.7179	0.7179	0.7450	0.7450
1050	0.6081	0.5810	0.7040	0.6906	0.7357	0.7268
1200	0.5799	0.5253	0.6901	0.6631	0.7265	0.7086
1350	0.5514	0.4689	0.6761	0.6354	0.7171	0.6902
1500	0.4900	0.3458	0.6461	0.5753	0.6973	0.6506

Table: D.5
STEAM QUALITY VS. DEPTH FOR DIFFERENT
RATES AND ZERO AND ONE-HALF STEAM
OFF-TAKE AT 1200 FT DEPTH; TIME = 900 DAYS
INJ. PRESS. 1500PSIA

Legend:

D : Depth, FT
 N O-T : No Off-Take
 H O-T : Half Off-Take

Steam Quality, Fraction

D	600 Bbls/Day		1200 Bbls/Day		1800 Bbls/Day	
	N O-T	H O-T	N O-T	H O-T	H O-T	N O-T
0	0.8000	0.8000	0.8000	0.8000	0.8000	0.8000
150	0.7731	0.7731	0.7864	0.7864	0.7909	0.7909
300	0.7461	0.7461	0.7728	0.7728	0.7817	0.7817
450	0.7189	0.7189	0.7592	0.7592	0.7726	0.7726
600	0.6916	0.6916	0.7455	0.7455	0.7634	0.7634
750	0.6640	0.6640	0.7317	0.7317	0.7542	0.7542
900	0.6362	0.6362	0.7179	0.7179	0.7450	0.7450
1050	0.6081	0.5810	0.7040	0.6906	0.7357	0.7268
1200	0.5799	0.5253	0.6901	0.6631	0.7265	0.7086
1350	0.5514	0.4689	0.6761	0.6354	0.7171	0.6902
1500	0.4900	0.3458	0.6461	0.5753	0.6973	0.6506

Table: D.6
STEAM QUALITY VS. DEPTH FOR DIFFERENT
RATES AND ZERO AND ONE-HALF STEAM
OFF-TAKE AT 1200 FT DEPTH; TIME = 1100 DAYS
INJ. PRESS. 1500PSIA

Legend:

D : Depth, FT
 N O-T : No Off-Take
 H O-T : Half Off-Take

Steam Quality, Fraction

D	600 Bbls/Day		1200 Bbls/Day		1800 Bbls/Day	
	N O-T	H O-T	N O-T	H O-T	H O-T	N O-T
0	0.8000	0.8000	0.8000	0.8000	0.8000	0.8000
150	0.7731	0.7731	0.7864	0.7864	0.7909	0.7909
300	0.7461	0.7461	0.7728	0.7728	0.7817	0.7817
450	0.7189	0.7189	0.7592	0.7592	0.7726	0.7726
600	0.6916	0.6916	0.7455	0.7455	0.7634	0.7634
750	0.6640	0.6640	0.7317	0.7317	0.7542	0.7542
900	0.6362	0.6362	0.7179	0.7179	0.7450	0.7450
1050	0.6081	0.5810	0.7040	0.6906	0.7357	0.7268
1200	0.5799	0.5253	0.6901	0.6631	0.7265	0.7086
1350	0.5514	0.4689	0.6761	0.6354	0.7171	0.6902
1500	0.4900	0.3458	0.6461	0.5753	0.6973	0.6506

Table: D.7
STEAM QUALITY VS. DEPTH FOR DIFFERENT
RATES AND ZERO AND ONE-HALF STEAM
OFF-TAKE AT 1200 FT DEPTH; TIME = 100 DAYS
INJ. PRESS. 1500PSIA

Legend:

D : Depth, FT
 N O-T : No Off-Take
 H O-T : Half Off-Take

Steam Pressure, psia

D	600 Bbls/Day		1200 Bbls/Day		1800 Bbls/Day	
	N O-T	H O-T	N O-T	H O-T	H O-T	N O-T
0	1500.0	1500.0	1500.0	1500.0	1500.0	1500.0
150	1525.0	1525.0	1519.6	1519.6	1517.2	1517.2
300	1550.5	1550.5	1539.4	1539.4	1534.6	1534.6
450	1576.4	1576.4	1559.5	1559.5	1552.2	1552.2
600	1602.9	1602.9	1579.8	1579.8	1569.9	1569.9
750	1629.9	1629.9	1600.3	1600.3	1587.7	1587.7
900	1657.5	1657.5	1621.2	1621.2	1605.8	1605.8
1050	1685.7	1692.0	1642.2	1647.9	1624.0	1628.6
1200	1714.5	1727.4	1663.6	1675.1	1642.4	1651.8
1350	1743.9	1762.4	1685.2	1702.9	1660.9	1675.3
1500	1774.3	1799.8	1707.3	1731.6	1679.7	1699.4

Table: D.8
STEAM QUALITY VS. DEPTH FOR DIFFERENT
RATES AND ZERO AND ONE-HALF STEAM
OFF-TAKE AT 1200 FT DEPTH; TIME = 300 DAYS
INJ. PRESS. 1500PSIA

Legend:

D : Depth, FT
 N O-T : No Off-Take
 H O-T : Half Off-Take

Steam Pressure, psia

D	600 Bbls/Day		1200 Bbls/Day		1800 Bbls/Day	
	N O-T	H O-T	N O-T	H O-T	H O-T	N O-T
0	1500.0	1500.0	1500.0	1500.0	1500.0	1500.0
150	1525.0	1525.0	1519.6	1519.6	1517.2	1517.2
300	1550.4	1550.4	1539.4	1539.4	1534.6	1534.6
450	1576.3	1576.3	1559.4	1559.4	1552.2	1552.2
600	1602.8	1602.8	1579.7	1579.7	1569.9	1569.9
750	1629.7	1629.7	1600.3	1600.3	1587.7	1587.7
900	1657.2	1657.2	1621.0	1621.0	1605.7	1605.7
1050	1685.3	1691.5	1642.1	1647.7	1623.9	1628.5
1200	1713.9	1726.7	1663.4	1674.9	1642.2	1651.5
1350	1743.1	1763.0	1685.0	1702.5	1660.7	1674.9
1500	1773.3	1800.0	1707.0	1731.1	1679.5	1698.9

Table: D.9
STEAM QUALITY VS. DEPTH FOR DIFFERENT
RATES AND ZERO AND ONE-HALF STEAM
OFF-TAKE AT 1200 FT DEPTH; TIME = 500 DAYS
INJ. PRESS. 1500PSIA

Legend:

D : Depth, FT
 N O-T : No Off-Take
 H O-T : Half Off-Take

Steam Pressure, psia

D	600 Bbls/Day		1200 Bbls/Day		1800 Bbls/Day	
	N O-T	H O-T	N O-T	H O-T	H O-T	N O-T
0	1500.0	1500.0	1500.0	1500.0	1500.0	1500.0
150	1525.0	1525.0	1519.6	1519.6	1517.2	1517.2
300	1550.4	1550.4	1539.4	1539.4	1534.6	1534.6
450	1576.3	1576.3	1559.4	1559.4	1552.2	1552.2
600	1602.8	1602.8	1579.7	1579.7	1569.9	1569.9
750	1629.7	1629.7	1600.3	1600.3	1587.7	1587.7
900	1657.2	1657.2	1621.0	1621.0	1605.7	1605.7
1050	1685.2	1691.5	1642.1	1647.7	1623.9	1628.5
1200	1713.9	1726.7	1663.4	1674.8	1642.2	1651.5
1350	1743.1	1762.9	1685.0	1702.5	1660.7	1674.9
1500	1773.2	1800.0	1706.9	1731.0	1679.5	1698.9

Table: D.10
STEAM QUALITY VS. DEPTH FOR DIFFERENT
RATES AND ZERO AND ONE-HALF STEAM
OFF-TAKE AT 1200 FT DEPTH; TIME = 700 DAYS
INJ. PRESS. 1600PSIA

Legend:

D : Depth, FT
 N O-T : No Off-Take
 H O-T : Half Off-Take

Steam Pressure, psia

D	600 Bbls/Day		1200 Bbls/Day		1800 Bbls/Day	
	N O-T	H O-T	N O-T	H O-T	H O-T	N O-T
0	1500.0	1500.0	1500.0	1500.0	1500.0	1500.0
150	1525.0	1525.0	1519.6	1519.6	1517.2	1517.2
300	1550.4	1550.4	1539.4	1539.4	1534.6	1534.6
450	1576.3	1576.3	1559.4	1559.4	1552.2	1552.2
600	1602.8	1602.8	1579.7	1579.7	1569.9	1569.9
750	1629.7	1629.7	1600.3	1600.3	1587.7	1587.7
900	1657.2	1657.2	1621.0	1621.0	1605.7	1605.7
1050	1685.2	1691.5	1642.1	1647.7	1623.9	1628.5
1200	1713.9	1726.7	1663.4	1674.8	1642.2	1651.5
1350	1743.1	1762.9	1685.0	1702.5	1660.7	1674.9
1500	1773.2	1800.0	1706.9	1731.0	1679.5	1698.9

Table: D.11
STEAM QUALITY VS. DEPTH FOR DIFFERENT
RATES AND ZERO AND ONE-HALF STEAM
OFF-TAKE AT 1200 FT DEPTH; TIME = 900 DAYS
INJ. PRESS. 1500PSIA

Legend:

D : Depth, FT
 N O-T : No Off-Take
 H O-T : Half Off-Take

Steam Pressure, psia

D	600 Bbls/Day		1200 Bbls/Day		1800 Bbls/Day	
	N O-T	H O-T	N O-T	H O-T	H O-T	N O-T
0	1500.0	1500.0	1500.0	1500.0	1500.0	1500.0
150	1525.0	1525.0	1519.6	1519.6	1517.2	1517.2
300	1550.4	1550.4	1539.4	1539.4	1534.6	1534.6
450	1576.3	1576.3	1559.4	1559.4	1552.2	1552.2
600	1602.8	1602.8	1579.7	1579.7	1569.9	1569.9
750	1629.7	1629.7	1600.3	1600.3	1587.7	1587.7
900	1657.2	1657.2	1621.0	1621.0	1605.7	1605.7
1050	1685.2	1691.5	1642.1	1647.7	1623.9	1628.5
1200	1713.9	1726.7	1663.4	1674.8	1642.2	1651.5
1350	1743.1	1762.9	1685.0	1702.5	1660.7	1674.9
1500	1773.2	1800.0	1706.9	1731.0	1679.5	1698.9

Table: D.12
STEAM QUALITY VS. DEPTH FOR DIFFERENT
RATES AND ZERO AND ONE-HALF STEAM
OFF-TAKE AT 1200 FT DEPTH; TIME = 1100 DAYS
INJ. PRESS. 1500PSIA

Legend:

D : Depth, FT
 N O-T : No Off-Take
 H O-T : Half Off-Take

Steam Pressure, psia

D	600 Bbls/Day		1200 Bbls/Day		1800 Bbls/Day	
	N O-T	H O-T	N O-T	H O-T	H O-T	N O-T
0	1500.0	1500.0	1500.0	1500.0	1500.0	1500.0
150	1525.0	1525.0	1519.6	1519.6	1517.2	1517.2
300	1550.4	1550.4	1539.4	1539.4	1534.6	1534.6
450	1576.3	1576.3	1559.4	1559.4	1552.2	1552.2
600	1602.8	1602.8	1579.7	1579.7	1569.9	1569.9
750	1629.7	1629.7	1600.3	1600.3	1587.7	1587.7
900	1657.2	1657.2	1621.0	1621.0	1605.7	1605.7
1050	1685.2	1691.5	1642.1	1647.7	1623.9	1628.5
1200	1713.9	1726.7	1663.4	1674.8	1642.2	1651.5
1350	1743.1	1762.9	1685.0	1702.5	1660.7	1674.9
1500	1773.2	1800.0	1706.9	1731.0	1679.5	1698.9

Table: D.13
 STEAM QUALITY VS. DEPTH FOR DIFFERENT
 RATES AND ZERO AND ONE-HALF STEAM
 OFF-TAKE AT 1200 FT DEPTH; TIME = 100 DAYS
 INJ. PRESS. 750PSIA

Legend:

D : Depth, FT
 N O-T : No Off-Take
 H O-T : Half Off-Take

Steam Quality, Fraction

D	600 Bbls/Day		1200 Bbls/Day		1800 Bbls/Day	
	N O-T	H O-T	N O-T	H O-T	H O-T	N O-T
0	0.8000	0.8000	0.8000	0.8000	0.8000	0.8000
150	0.7799	0.7799	0.7897	0.7897	0.7930	0.7930
300	0.7594	0.7594	0.7793	0.7793	0.7859	0.7859
450	0.7387	0.7387	0.7688	0.7688	0.7788	0.7788
600	0.7178	0.7178	0.7582	0.7582	0.7717	0.7717
750	0.6966	0.6966	0.7476	0.7476	0.7645	0.7645
900	0.6753	0.6753	0.7369	0.7369	0.7573	0.7573
1050	0.6537	0.6329	0.7262	0.7160	0.7500	0.7433
1200	0.6318	0.5899	0.7154	0.6949	0.7428	0.7292
1350	0.6098	0.5462	0.7045	0.6735	0.7355	0.7150
1500	0.5672	0.4603	0.6838	0.6322	0.7218	0.6878

Table: D.14
STEAM QUALITY VS. DEPTH FOR DIFFERENT
RATES AND ZERO AND ONE-HALF STEAM
OFF-TAKE AT 1200 FT DEPTH; TIME = 300 DAYS
INJ. PRESS. 750PSIA

Legend:

D : Depth, FT
 N O-T : No Off-Take
 H O-T : Half Off-Take

Steam Quality, Fraction

D	600 Bbls/Day		1200 Bbls/Day		1800 Bbls/Day	
	N O-T	H O-T	N O-T	H O-T	H O-T	N O-T
0	0.8000	0.8000	0.8000	0.8000	0.8000	0.8000
150	0.7807	0.7807	0.7901	0.7901	0.7933	0.7933
300	0.7611	0.7611	0.7801	0.7801	0.7865	0.7865
450	0.7413	0.7413	0.7701	0.7701	0.7796	0.7796
600	0.7212	0.7212	0.7599	0.7599	0.7728	0.7728
750	0.7010	0.7010	0.7498	0.7498	0.7659	0.7659
900	0.6805	0.6805	0.7395	0.7395	0.7590	0.7590
1050	0.6598	0.6400	0.7292	0.7195	0.7520	0.7456
1200	0.6390	0.5989	0.7188	0.6992	0.7451	0.7321
1350	0.6178	0.5571	0.7084	0.6788	0.7381	0.7185
1500	0.5753	0.4714	0.6878	0.6375	0.7244	0.6913

Table: D.15
STEAM QUALITY VS. DEPTH FOR DIFFERENT
RATES AND ZERO AND ONE-HALF STEAM
OFF-TAKE AT 1200 FT DEPTH; TIME = 500 DAYS
INJ. PRESS. 750PSIA

Legend:

D : Depth, FT
 N O-T : No Off-Take
 H O-T : Half Off-Take

Steam Quality, Fraction

D	600 Bbls/Day		1200 Bbls/Day		1800 Bbls/Day	
	N O-T	H O-T	N O-T	H O-T	H O-T	N O-T
0	0.8000	0.8000	0.8000	0.8000	0.8000	0.8000
150	0.7807	0.7807	0.7901	0.7901	0.7933	0.7933
300	0.7611	0.7611	0.7801	0.7801	0.7865	0.7865
450	0.7413	0.7413	0.7701	0.7701	0.7797	0.7797
600	0.7213	0.7213	0.7600	0.7600	0.7728	0.7728
750	0.7011	0.7011	0.7498	0.7498	0.7659	0.7659
900	0.6807	0.6807	0.7396	0.7396	0.7590	0.7590
1050	0.6600	0.6402	0.7293	0.7196	0.7521	0.7457
1200	0.6391	0.5991	0.7189	0.6993	0.7451	0.7322
1350	0.6180	0.5574	0.7085	0.6789	0.7381	0.7186
1500	0.5755	0.4716	0.6879	0.6376	0.7244	0.6914

Table: D.16
 STEAM QUALITY VS. DEPTH FOR DIFFERENT
 RATES AND ZERO AND ONE-HALF STEAM
 OFF-TAKE AT 1200 FT DEPTH; TIME = 700 DAYS
 INJ. PRESS. 750PSIA

Legend:

D : Depth, FT
 N O-T : No Off-Take
 H O-T : Half Off-Take

Steam Quality, Fraction

D	600 Bbls/Day		1200 Bbls/Day		1800 Bbls/Day	
	N O-T	H O-T	N O-T	H O-T	H O-T	N O-T
0	0.8000	0.8000	0.8000	0.8000	0.8000	0.8000
150	0.7807	0.7807	0.7901	0.7901	0.7933	0.7933
300	0.7611	0.7611	0.7801	0.7801	0.7865	0.7865
450	0.7413	0.7413	0.7701	0.7701	0.7797	0.7797
600	0.7213	0.7213	0.7600	0.7600	0.7728	0.7728
750	0.7011	0.7011	0.7498	0.7498	0.7659	0.7659
900	0.6807	0.6807	0.7396	0.7396	0.7590	0.7590
1050	0.6600	0.6402	0.7293	0.7196	0.7521	0.7457
1200	0.6391	0.5991	0.7189	0.6993	0.7451	0.7322
1350	0.6180	0.5574	0.7085	0.6789	0.7381	0.7186
1500	0.5755	0.4716	0.6879	0.6376	0.7244	0.6914

Table: D.17
 STEAM QUALITY VS. DEPTH FOR DIFFERENT
 RATES AND ZERO AND ONE-HALF STEAM
 OFF-TAKE AT 1200 FT DEPTH; TIME = 900 DAYS
 INJ. PRESS. 750PSIA

Legend:

D : Depth, FT
 N O-T : No Off-Take
 H O-T : Half Off-Take

Steam Quality, Fraction

D	600 Bbls/Day		1200 Bbls/Day		1800 Bbls/Day	
	N O-T	H O-T	N O-T	H O-T	H O-T	N O-T
0	0.8000	0.8000	0.8000	0.8000	0.8000	0.8000
150	0.7807	0.7807	0.7901	0.7901	0.7933	0.7933
300	0.7611	0.7611	0.7801	0.7801	0.7865	0.7865
450	0.7413	0.7413	0.7701	0.7701	0.7797	0.7797
600	0.7213	0.7213	0.7600	0.7600	0.7728	0.7728
750	0.7011	0.7011	0.7498	0.7498	0.7659	0.7659
900	0.6807	0.6807	0.7396	0.7396	0.7590	0.7590
1050	0.6600	0.6402	0.7293	0.7196	0.7521	0.7457
1200	0.6391	0.5991	0.7189	0.6993	0.7451	0.7322
1350	0.6180	0.5574	0.7085	0.6789	0.7381	0.7186
1500	0.5755	0.4716	0.6879	0.6376	0.7244	0.6914

Table: D.18
 STEAM QUALITY VS. DEPTH FOR DIFFERENT
 RATES AND ZERO AND ONE-HALF STEAM
 OFF-TAKE AT 1200 FT DEPTH; TIME = 1100 DAYS
 INJ. PRESS. 750PSIA

Legend:

D : Depth, FT
 N O-T : No Off-Take
 H O-T : Half Off-Take

Steam Quality, Fraction

D	600 Bbls/Day		1200 Bbls/Day		1800 Bbls/Day	
	N O-T	H O-T	N O-T	H O-T	H O-T	N O-T
0	0.8000	0.8000	0.8000	0.8000	0.8000	0.8000
150	0.7807	0.7807	0.7901	0.7901	0.7933	0.7933
300	0.7611	0.7611	0.7801	0.7801	0.7865	0.7865
450	0.7413	0.7413	0.7701	0.7701	0.7797	0.7797
600	0.7213	0.7213	0.7600	0.7600	0.7728	0.7728
750	0.7011	0.7011	0.7498	0.7498	0.7659	0.7659
900	0.6807	0.6807	0.7396	0.7396	0.7590	0.7590
1050	0.6600	0.6402	0.7293	0.7196	0.7521	0.7457
1200	0.6391	0.5991	0.7189	0.6993	0.7451	0.7322
1350	0.6180	0.5574	0.7085	0.6789	0.7381	0.7186
1500	0.5755	0.4716	0.6879	0.6376	0.7244	0.6914

Table: D.19
STEAM QUALITY VS. DEPTH FOR DIFFERENT
RATES AND ZERO AND ONE-HALF STEAM
OFF-TAKE AT 1200 FT DEPTH; TIME = 100 DAYS
INJ. PRESS. 750PSIA

Legend:

D : Depth, FT
 N O-T : No Off-Take
 H O-T : Half Off-Take

Steam Pressure, psia

D	600 Bbls/Day		1200 Bbls/Day		1800 Bbls/Day	
	N O-T	H O-T	N O-T	H O-T	H O-T	N O-T
0	750.0	750.0	750.0	750.0	750.0	750.0
150	770.0	770.0	765.7	765.7	764.0	764.0
300	790.4	790.4	781.6	781.6	778.0	778.0
450	811.3	811.3	797.6	797.6	792.2	792.2
600	832.5	832.5	813.9	813.9	806.5	806.5
750	854.2	854.2	830.3	830.3	821.0	821.0
900	876.4	876.4	847.0	847.0	835.5	835.5
1050	899.0	905.7	863.8	868.6	850.2	853.8
1200	922.2	936.0	880.9	890.6	865.1	872.3
1350	945.9	967.3	898.1	913.1	880.0	891.2
1500	970.3	1000.2	915.7	936.2	895.1	910.4

Table: D.20
 STEAM QUALITY VS. DEPTH FOR DIFFERENT
 RATES AND ZERO AND ONE-HALF STEAM
 OFF-TAKE AT 1200 FT DEPTH; TIME = 300 DAYS
 INJ. PRESS. 750PSIA

Legend:

D : Depth, FT
 N O-T : No Off-Take
 H O-T : Half Off-Take

Steam Pressure, psia

D	600 Bbls/Day		1200 Bbls/Day		1800 Bbls/Day	
	N O-T	H O-T	N O-T	H O-T	H O-T	N O-T
0	750.0	750.0	750.0	750.0	750.0	750.0
150	770.0	770.0	765.7	765.7	764.0	764.0
300	790.4	790.4	781.6	781.6	778.0	778.0
450	811.2	811.2	797.6	797.6	792.2	792.2
600	832.4	832.4	813.9	813.9	806.5	806.5
750	854.1	854.1	830.3	830.3	821.0	821.0
900	876.2	876.2	846.9	846.9	835.5	835.5
1050	898.8	905.4	863.7	868.5	850.2	853.8
1200	921.8	935.6	880.8	890.4	865.0	872.3
1350	945.4	966.7	898.0	912.9	879.9	891.1
1500	969.7	999.3	915.5	936.9	895.0	910.2

Table: D.21
STEAM QUALITY VS. DEPTH FOR DIFFERENT
RATES AND ZERO AND ONE-HALF STEAM
OFF-TAKE AT 1200 FT DEPTH; TIME = 500 DAYS
INJ. PRESS. 750PSIA

Legend:

D : Depth, FT
 N O-T : No Off-Take
 H O-T : Half Off-Take

Steam Pressure, psia

D	600 Bbls/Day		1200 Bbls/Day		1800 Bbls/Day	
	N O-T	H O-T	N O-T	H O-T	H O-T	N O-T
0	750.0	750.0	750.0	750.0	750.0	750.0
150	770.0	770.0	765.7	765.7	764.0	764.0
300	790.4	790.4	781.6	781.6	778.0	778.0
450	811.2	811.2	797.6	797.6	792.2	792.2
600	832.4	832.4	813.9	813.9	806.5	806.5
750	854.1	854.1	830.3	830.3	821.0	821.0
900	876.2	876.2	846.9	846.9	835.5	835.5
1050	898.8	905.4	863.7	868.5	850.2	853.8
1200	921.8	935.6	880.8	890.4	865.0	872.3
1350	945.4	966.7	898.0	913.9	879.9	891.1
1500	969.7	999.3	915.5	936.9	895.0	910.2

Table: D.22
STEAM QUALITY VS. DEPTH FOR DIFFERENT
RATES AND ZERO AND ONE-HALF STEAM
OFF-TAKE AT 1200 FT DEPTH; TIME = 700 DAYS
INJ. PRESS. 760PSIA

Legend:

D : Depth, FT
 N O-T : No Off-Take
 H O-T : Half Off-Take

Steam Pressure, psia

D	600 Bbls/Day		1200 Bbls/Day		1800 Bbls/Day	
	N O-T	H O-T	N O-T	H O-T	H O-T	N O-T
0	750.0	750.0	750.0	750.0	750.0	750.0
150	770.0	770.0	765.7	765.7	764.0	764.0
300	790.4	790.4	781.6	781.6	778.0	778.0
450	811.2	811.2	797.6	797.6	792.2	792.2
600	832.4	832.4	813.9	813.9	806.5	806.5
750	854.1	854.1	830.3	830.3	821.0	821.0
900	876.2	876.2	846.9	846.9	835.5	835.5
1050	898.8	905.4	863.7	868.5	850.2	853.8
1200	921.8	935.6	880.8	890.4	865.0	872.3
1350	945.4	966.7	898.0	913.9	879.9	891.1
1500	969.7	999.3	915.5	936.9	895.0	910.2

Table: D.23
STEAM QUALITY VS. DEPTH FOR DIFFERENT
RATES AND ZERO AND ONE-HALF STEAM
OFF-TAKE AT 1200 FT DEPTH; TIME = 900 DAYS
INJ. PRESS. 750PSIA

Legend:

D : Depth, FT
 N O-T : No Off-Take
 H O-T : Half Off-Take

Steam Pressure, psia

D	600 Bbls/Day		1200 Bbls/Day		1800 Bbls/Day	
	N O-T	H O-T	N O-T	H O-T	H O-T	N O-T
0	750.0	750.0	750.0	750.0	750.0	750.0
150	770.0	770.0	765.7	765.7	764.0	764.0
300	790.4	790.4	781.6	781.6	778.0	778.0
450	811.2	811.2	797.6	797.6	792.2	792.2
600	832.4	832.4	813.9	813.9	806.5	806.5
750	854.1	854.1	830.3	830.3	821.0	821.0
900	876.2	876.2	846.9	846.9	835.5	835.5
1050	898.8	905.4	863.7	868.5	850.2	853.8
1200	921.8	935.6	880.8	890.4	865.0	872.3
1350	945.4	966.7	898.0	913.9	879.9	891.1
1500	969.7	999.3	915.5	936.9	895.0	910.2

Table: D.24
STEAM QUALITY VS. DEPTH FOR DIFFERENT
RATES AND ZERO AND ONE-HALF STEAM
OFF-TAKE AT 1200 FT DEPTH; TIME = 1100 DAYS
INJ. PRESS. 750PSIA

Legend:

D : Depth, FT
 N O-T : No Off-Take
 H O-T : Half Off-Take

Steam Pressure, psia

D	600 Bbls/Day		1200 Bbls/Day		1800 Bbls/Day	
	N O-T	H O-T	N O-T	H O-T	H O-T	N O-T
0	750.0	750.0	750.0	750.0	750.0	750.0
150	770.0	770.0	765.7	765.7	764.0	764.0
300	790.4	790.4	781.6	781.6	778.0	778.0
450	811.2	811.2	797.6	797.6	792.2	792.2
600	832.4	832.4	813.9	813.9	806.5	806.5
750	854.1	854.1	830.3	830.3	821.0	821.0
900	876.2	876.2	846.9	846.9	835.5	835.5
1050	898.8	905.4	863.7	868.5	850.2	853.8
1200	921.8	935.6	880.8	890.4	865.0	872.3
1350	945.4	966.7	898.0	913.9	879.9	891.1
1500	969.7	999.3	915.5	936.9	895.0	910.2

APPENDIX E
PAPERS PRESENTED DURING THE PROJECT PERIOD

THIS IS A PREPRINT — SUBJECT TO CORRECTION

STEAMFLOODING LIGHT AND MODERATELY VISCOUS OIL RESERVOIRS IN ALBERTA

by
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THIS PAPER IS TO BE PRESENTED AT THE 37th ANNUAL TECHNICAL MEETING OF THE PETROLEUM SOCIETY OF CIM HELD IN CALGARY, JUNE 8-11, 1986. DISCUSSION OF THIS PAPER IS INVITED. SUCH DISCUSSION MAY BE PRESENTED AT THE TECHNICAL MEETING AND WILL BE CONSIDERED FOR PUBLICATION IN CIM JOURNALS IF FILED IN WRITING WITH THE TECHNICAL PROGRAM CHAIRMAN PRIOR TO THE CONCLUSION OF THE MEETING.

ABSTRACT

Steamflooding can be an efficient and economically viable recovery technique for light oils, under the right conditions. This paper includes a thorough review of the current state of steamflood technology as applied to light and moderately viscous oil reservoirs, including a description of the mechanisms involved in the steamflood recovery process. The paper also gives the results of selected scaled model studies of a light oil steamflood, showing the type of drive to expect in the field.

An elementary numerical simulator, employing the Mandl-Volek method, was developed to examine the potential for light oil steamflooding in Alberta. One hundred and fifteen reservoirs in Alberta were examined and it was found that at least ten of Alberta's light oil reservoirs are suitable for steamflooding. These reservoirs are listed, and predicted steamflood recoveries and oil-steam ratios are given. Criteria for steamflooding a light oil reservoir are suggested in light of the results obtained.

The chief concerns in light oil steamfloods are (i) the initial oil saturation, (ii) the formation porosity, and (iii) the formation thickness. It is concluded that the porosity-oil saturation product should be at least 0.1 and that minimum formation thickness should be about six metres.

Other factors to consider include depth, reservoir pressure, and steam injectivity.

INTRODUCTION

Steam injection is a proven method of oil recovery which has been widely successful in recovery operations around the world. It currently accounts for over 80% of all oil produced in the world by enhanced recovery methods.¹ Of the two steam injection methods being employed, viz. cyclic steam stimulation and steamflooding, we shall consider only the latter, because cyclic steaming is only appropriate for heavy oils.

The efficiency of steamflooding is evident in California heavy oil reservoirs where steamflooding has resulted in oil recoveries of as much as 77% (San Ardo) with 55-60% being commonplace. There is a growing belief that this heavy oil steamflood technology can be applied with similar success to light oil reservoirs to recover waterflood residual oil.

Following primary production, light oil reservoirs are typically waterflooded to increase the ultimate oil recovery. However, such waterflooding operations still leave a considerable volume of unrecovered oil. Waterflood residual oil saturations are generally in the range of 40 to 50% and may be much greater.

Several methods have been proposed to recover waterflood residual oil. These include micellar/polymer flooding, alkaline flooding, microbial techniques, and miscible and immiscible gas injection. However, in many instances, the incremental recoveries from such operations are not economical.

A number of field tests have been conducted (listed later in the paper), where a steamflood was carried out in a light oil reservoir. Several of these have been successful. Unlike heavy oils where oil viscosity is of primary concern, light oil recovery by steamflooding is strongly dependent on the steam distillation effect, which results in extremely low residual oil saturations in the steamed-off zone. Studies have shown that the steamflood residual oil saturation approaches zero in the case of a light oil. Steamflooding is one of the few recovery processes that has been successful for the tertiary recovery of waterflood residual oil.

STEAMFLOODING LIGHT OIL RESERVOIRS

Steamflood Recovery Mechanisms--General

One of the earliest laboratory studies dealing with steam injection was conducted by Willman et al.¹ This work provided much useful information on the mechanisms involved in a steamflood operation. The experiments were carried out using linear cores saturated with refined and crude oils having varying viscosities and steam distillation properties. Of particular significance, the results showed an increase in oil recovery by steam injection as much as 100% greater than oil recoveries by waterflood. The improvement in recovery was attributed to (1) thermal expansion of the oil, (2) viscosity reduction, and (3) steam distillation effects.

Prats² presents a detailed listing of the relative importance of numerous phenomena occurring in thermal recovery processes. He notes that viscosity reduction, gravity drainage, and distillation effects are the predominant recovery mechanisms in a steam drive operation.

Based on their literature review, Blevins, Duerksen, and Ault³ list the following as the major steamflood recovery mechanisms: (1) viscosity reduction, (2) steam distillation, (3) distillate (in-situ solvent) drive, (4) gas drive, (5) thermal expansion, (6) relative permeability variation, and (7) gravity segregation.

Farouq Ali⁴ examined in detail several of the theories which have been proposed to explain the mechanics of steam advance in an oil-bearing formation with the objective of developing criteria to determine which theory best describes a particular situation. The paper discussed steam front stability, steam zone development, gravity segregation of steam, effect of formation thickness, and steam injection into fractures. A method of predicting steamflood performance was also outlined in the paper.

Steamflood Recovery Mechanisms--Light Oil Reservoirs

Studies have shown that the factors influencing steamflood recovery of light oils are similar to those affecting heavy oils, but the relative

importance of each of the contributing factors is very different. For example, it is estimated that 5-10% of the heavy oil recovered in a steamflood operation may be attributed to steam distillation, but in a light oil steam injection process, the contribution to recovery due to steam distillation may be as high as 60%.⁵

Steam distillation

Ellerbe⁶ provides a comprehensive description of steam distillation. He notes that steam distillation relies on the unique vapour pressure behavior of immiscible liquids. Boiling begins when the sum of the partial pressures of the steam and the material distilled reach the system pressure. When the vapours condense, two distinct substances result from the originally distilled material.

Duerksen and Hsueh³ describe the steam distillation process with respect to oil recovery in more detail. They state that a fraction of the crude oil in the steam zone vaporizes into the steam phase according to the vapour pressures of the hydrocarbon constituents contained in the crude oil, and that this hydrocarbon vapour is transported through the steam zone by the flowing steam. At the steam front, the steam and the hydrocarbon vapour condense to form a hot water zone and a hydrocarbon distillate bank. The authors state that the vaporization, transport and condensation of the hydrocarbon fractions is a dynamic process that displaces the lighter hydrocarbon fractions and generates a distillate bank that miscibly drives reservoir oil to producing wells.

Considerable work has been done to examine the importance of steam distillation in thermal recovery operations and to attempt to quantify the effects for prediction purposes.

Sukkar¹⁰ outlined a mathematical procedure for calculating the fraction of the oil which is evaporated from residual reservoir oil and the fraction which condenses with the steam. The procedure assumes that crude oil components having a velocity greater than the velocity of the condensing steam front would be completely distilled and would condense at or beyond the leading edge of the steam front.

Johnson, Walker, and Bayazeed¹¹ present another method for predicting the amount of oil distilled in a steam zone during steamflooding. A relationship to determine the percent of oil vaporized as a function of the amount of steam contacting the oil was developed based on two laboratory experiments. Their calculations indicated that oil vaporization increases with an increase in steam temperature, but decreases with an increase in steam injection rate.

Wu and Brown¹² present the results of thirteen experiments, conducted on six crude oils with viscosities ranging from 5 to 140,000 centistokes at 80°F (26.7°C). They concluded that the equilibrium saturated steam distillation yields are mainly dependent on the oil composition and may not correlate with crude API gravity. They also stated that steam distillation yields appeared to be independent of porous media, initial oil volume, and steam injection rate.

Elder and Wu¹¹ examined the steam distillation yields for 16 crude oils ranging in gravity from 12 to 40° API. They reached two important conclusions based upon a regression analysis of their results: that the steam distillation yield (i) increases linearly with respect to API gravity, and (ii) decreases logarithmically with respect to the oil viscosity at 100°F (37.8°C).

Duerksen and Hseuh⁸ conducted thirteen steam distillation tests on ten crude oils ranging in gravity from 9.4 to 37° API. Unlike previous work, their analysis included an examination of the importance of paraffin and wax content of the crudes. They concluded that steam distillation yields at steamflood conditions are significant even for heavy oils, and that the steam distillation yield correlates well with API gravity and wax content.

Laboratory Studies of Light Oil Steamflooding

Ozen and Farouq Ali¹² investigated the possibility of steamflooding light oil reservoirs. They conducted experiments in linear, consolidated cores under isothermal conditions and found that the steam drive can be an effective process to recover waterflood residual oil.

Myal and Farouq Ali¹³ conducted isothermal core flood experiments using ten crude samples from ten producing formations in the Penn-Grade area of Pennsylvania. They found that the steamflood residual oil saturation for each type of crude was independent of the initial oil saturation in the core, and ranged from 7.3% to 17.5% for the various crudes.

Hagoort, Leijnse, and van Poelgeest¹⁴ conducted a study involving laboratory experiments and mathematical simulators to examine the oil recovery of a particular prototype by "steam stripping" (distillation). (They define stripping as the mass transfer of volatile components from a liquid into a passing gas stream.) They concluded that steam-stripping can be a viable recovery process, particularly for conditions of an oil with a low distillation residue, low reservoir pressures, high injection rates, thick layers, and high porosity.

Farouq Ali¹⁵ discussed the possibility of steam being used to recover waterflood residual oil from light or moderately viscous oil reservoirs. He suggested that the product of the rock porosity and the initial oil saturation must be greater than 0.10 for such an operation to be successful.

Hanzlik¹⁶ utilized a highly implicit reservoir simulator to predict steamflood performance to study the effects of final waterflood water-oil ratio, reservoir thickness, and amount of distillate component in the crude. He determined that the main factor affecting the ultimate oil recovery was the mole fraction of the oil which was distillable. Definite high saturation oil banks were observed to form due to the successive distillation-condensation cycles, as the distillable fraction moved through the reservoir. Hanzlik found that initiation of a steamflood prior to a waterflood becoming watered out reduces the ultimate steam-oil ratio; but he also found that the ultimate waterflood plus steamflood oil recovery was the same for a given reservoir,

regardless of whether the steamflood was started when the waterflood water-oil ratio was 50 or 100. Hanzlik suggested that many previously waterflooded, shallow, light oil reservoirs may be viable candidates for steamflooding.

Doscher¹⁷ discussed the drastic reduction in residual oil saturation resulting from light oil steamflooding. He noted that previous theories which suggested that the interfacial tension between steam and hot oil was so low as to cause a reduction in oil saturation were incorrect. He postulated that the high velocity of the steam vapour phase is the basis for the entrainment of heated oil by the steam and condensate at the interface between the overriding steam and underlying oil column, and it is this which drives the residual oil saturation to such low values. Based on scaled model experiments, Doscher also commented on the type of drive which occurs for a light oil steamflood stating that it approaches a frontal displacement rather than the steam channeling which is characteristic of more viscous oils. He concluded that for a reservoir containing high gravity crude, in which a high injection rate of high quality steam can be achieved, the steam drive is very competitive with a waterflood. He also suggested that if a noncondensable gas were substituted for a significant fraction of the steam in a mature steam drive it could result in a significant increase in the oil-steam ratio without affecting the overall recovery.

As part of the present study, steam injection experiments were conducted using light oil in a low pressure, scaled model apparatus. (A detailed description of the apparatus is given elsewhere by the principal author.²⁰) Scaling for the model was based upon the low pressure scaling criteria developed by Stegemeier, Laumbach, & Volek.²¹

The main purpose of these steamflood experiments was to examine the shape of the steam front in the displacement of a light oil. The model and model fluids represented a prototype with reservoir temperature viscosity of 25.6 mPa·s, pay thickness of 11 metres, porosity of 31%, and permeability of 2000 md. In these experiments, steam was injected continuously at a rate corresponding to a prototype injection rate of 100 m³/day (628 bbls/day).

Figure 1 shows the temperature distribution through a cross section of the model, from the injection well to the production well, after injecting 0.25 pore volumes of steam. Figures 2, 3, and 4 show the temperature distributions through this same cross section after injecting 0.50, 0.75, and 1.00 pore volumes of steam, respectively. In each of these figures, it can be seen that the heat advances more rapidly in the lower portion of the reservoir than in the upper portion. This is due to the rapid advance of the condensate zone in this part of the formation.

Summary of the Light Oil Steamflooding Process

The information revealed by the papers referenced above has been summarized to describe the process involved in recovering light oils by steamflooding.

Steam is injected into the oil bearing formation, where it partially displaces the oil, gas and water near the wellbore to form a steam zone, which is considered to be at a constant temperature. Some of the heat of the steam zone is lost to the overburden and underburden by conduction and, after a certain 'critical time' described by Mandl and Volek,²² heat is transferred at the front by convection.

Within the steam zone, the oil is heated and a reduction in viscosity occurs along with some amount of thermal expansion. In addition, a fraction of the oil is vaporized, the volume of which is a function of the vapour pressures of the hydrocarbon constituents of the oil. Relative permeability changes within the steamed-out zone are also thought to result in a manner advantageous to oil mobilization.

With continued steam injection, the steam zone expands in the direction of the production wells. The injected steam and hydrocarbon vapour flow toward the heat front where they condense to form a steam condensate bank in front of a distillate bank. The advance of the water bank and the distillate bank causes an oil bank to be formed ahead of the water bank. (If the reservoir is already at the minimum residual oil saturation to waterflood, this oil bank may not form.)

The distillate bank is miscible with the reservoir oil and serves to reduce the residual oil saturation as it advances. The marked reduction in residual oil saturation which results from the steam distillation and the miscible displacement of reservoir oil, is the main factor which establishes the improved incremental recovery above primary and waterflood production.

Field Tests of Light Oil Steamflooding

Volek and Pryor²³ reported on a field test conducted at Shell Oil's Brea Field in California. This test involved the displacement of a volatile oil (24° API) by steam. A core taken from a steamed zone of the formation revealed an average residual oil saturation of 8% and included several intervals with essentially zero oil saturation. They also observed an increase in the average API gravity of the oil. Volek and Pryor reported that the steam drive of a light oil is a relatively stable displacement process which is enhanced by both fluid convection and thermal conduction effects. They expanded on this by explaining that the higher volumetric flow rates in the steam zone compared to the condensate flow rate ahead of the steam front causes the pressure gradient to be large compared to that in the condensate zone; thus stabilizing the advance. They stated that heat losses at the front, normal to the direction of fluid flow, also tend to collapse irregularities in the steam front advance.

Bleakley²⁴ reported on a light oil steamflood conducted by Pennzoil on the Franklin Heavy Oil Pool in Pennsylvania. He noted that production increased from 1/4 barrel/day/well (primary) to a peak of 29 barrels/day for the single producer in the five-spot steam injection pilot project. At the end of the test, the oil saturation within the pilot area was reduced from 40% to 14%. Bleakley stated that the

project was not an economic success because of the low price of crude (\$4.73 US/bbl) at the time of the test (1964-1966).

Farouq Ali²⁵ discussed the results of a steamflood field test conducted on the Bradford crude of Pennsylvania, a light oil with reservoir temperature viscosity of 4 cp. A number of operational problems were encountered in this project. For example, because of high heat losses in the surface and wellbore tubing, low quality steam was injected into the formation. Also, fluid migration out of the pattern area was calculated to be approximately 10%.

Farouq Ali²⁵ developed a numerical simulator to predict the Bradford steamflood response, which showed good agreement with the actual field performance. He performed simulations to examine the effect of higher initial oil saturations and found that an initial oil saturation of 51% (17% greater than the actual initial oil saturation at the start of the steamflood) would result in much higher oil recovery and a greatly improved oil-steam ratio. He suggested that a major problem with the Bradford steamflood was the low initial oil saturation. In spite of the poor economics of the Bradford light oil steamflood, it was felt that the project was a technical success.

Blevins, Duerksen, and Ault²⁶ compiled a list of several other light oil steamflood operations. These include East Coalinga, California,²⁷ Smackover, Arkansas,²⁸ Triumph and Shamburgh, Pennsylvania,²⁹ El Dorado, Kansas,³⁰ Shiells Canyon, California,³¹ Fyzabad, Trinidad, Lacq Superieur, France, Lost Hills, California, and Emerand, Congo,³² Beuna Vista Hills, California,³³ and Humble, Texas.³⁴

Table 1 lists numerous field tests that have been conducted in which a steamflood was carried out in a light oil reservoir. From this list, it can be seen that the successful steamfloods had $\alpha \cdot S_o$ products greater than 0.10.

STEAMFLOOD PERFORMANCE PREDICTION FOR ALBERTA'S LIGHT OIL RESERVOIRS

An analysis was carried out to determine whether any of Alberta's light oil reservoirs are suitable for steamflooding. This analysis is intended only as a preliminary examination of the steamflood potential of the light oil reservoirs of Alberta and as such does not consider known heterogeneities or operational problems of individual reservoirs. The purpose of the paper is to demonstrate that several light oil reservoirs in Alberta are suitable for steamflooding and thus, the analysis should not be construed as a complete listing of all possible candidates. Reservoirs which showed good response to steamflooding in the simulation performed in this study should be examined in much greater detail, using all available data.

Reservoir information was obtained from a publication by the Energy Resources Conservation Board of Alberta.³⁵ This publication provides values for original oil in place, cumulative recovery to December 31, 1984, average reservoir thickness, reservoir area, average reservoir porosity, and shrinkage factor. From this publication, data for

115 pools was taken and these pools were considered in the steamflood analysis.

In view of the limited reservoir data available, only a rough estimate of the steamflood potential for the reservoirs under study was expected. Thus, a relatively simple numerical simulator was developed to predict steamflood performance. The calculation procedure assumes that the oil saturation within the steam zone is lowered to a constant value, S_{orst} and, at any time t , the oil recovery is given by the displaced oil.

There are several limitations to the procedure used to predict the steamflood recovery. It is assumed that the oil displaced from the steam zone is immediately produced. (Normally there would be a lag due to the banking process). Also, this method does not account for production resulting from condensate waterflooding ahead of the steam front and thus it is felt that the predicted oil recoveries and oil-steam ratios are significantly lower than would actually be observed in a field project.

Calculation Procedure

For the purposes of this study, 'typical' values were chosen to represent the reservoir and steam conditions. It must be emphasized that the results are only estimates and that further analysis should be performed using all available data, for the reservoirs which appear promising.

- i_s = rate of steam injection (water equivalent) = 100 m³/day (630 bbls/day)
- p = steam injection pressure = 2.0 MPa (~300 psia)
- f_s = steam quality = 0.70
- T_R = reservoir temperature = 30°C (86°F)
- k_{hob} = conductivity of the overburden = 2.0 W/m-K (1.2 Btu/hr-ft-°F)
- M_{ob} = heat capacity of the overburden = 2200 kJ/m³-K (32.5 Btu/ft³-°F)
- T_s = steam temperature = 212.4°C (414.3°F)
- M_s = formation volumetric heat capacity = 2400 kJ/m³-K (35 Btu/ft³-°F)
- h_w = enthalpy of saturated water at steam temperature = 908.4 kJ/kg
- L_v = latent heat of vaporization of saturated steam at steam temperature = 1889 kJ/kg
- h_s = enthalpy of saturated steam at steam temperature = 2797 kJ/kg
- h_r = enthalpy of water at reservoir temperature = 65 kJ/kg

Program Steps

At the start of the program, the data which will be used to represent the reservoir are input. Values

for h_t , h_n , ϕ , S_{oi} , S_{orst} , E_A , E_v , pattern size, and the time step must be supplied. These can be input in an interactive mode, or can be supplied to the program in a free format data file.

The oil in place prior to the steamflood is then determined by the following equation:

$$N = A \cdot h_n \cdot \phi \cdot S_{oi} \text{ in m}^3.$$

Next, the program calculates the maximum size of the steam zone before breakthrough.

$$V_{Sbt} = A \cdot h_t \cdot E_v \cdot E_A \text{ in m}^3.$$

At this point, the program calculates the critical time, t_c and then proceeds with the simulation. The time is incremented by the time step which was input previously. At each time step, the steam zone volume, the cumulative oil recovery, the cumulative oil-steam ratio, and the instantaneous oil-steam ratio are calculated and included in the output.

Reservoir Analysis

The 115 reservoirs which were examined in this study are listed in the appendices. These pools were chosen from the ERCB 'Alberta Reserves' publication, based on their thickness, porosity, and oil saturation (to December 31, 1984). Data from each of these reservoirs was input into the simulator and the steamflood potential was determined. Of the 115 reservoirs tested, 10 appeared to be suitable for steamflooding, while 11 others looked promising. These 21 reservoirs are listed in Table 2 with a prediction for breakthrough oil recoveries and initial oil-steam ratios. It should be emphasized that these predictions are thought to be conservative in that they do not consider oil production resulting from condensate flooding ahead of the front.

Criteria for a Successful Light Oil Steamflood

It can be observed in Table 2 that all of the fields found to have responded successfully to steamflooding have porosity-oil saturation products well over 0.10. Those reservoirs thought to hold promise for a successful steamflood operation also have ϕS_{oi} products of 0.10 or greater. It should be noted that the oil recovery is really proportional to the displacable oil, i.e. $\phi(S_{oi} - S_{orst})$. However, because S_{orst} for light oil is very low, ϕS_{oi} appears to be an adequate parameter. The thicknesses range from 4.35 to 55.17 meters (14.3 to 181 feet). The porosity of these pools is generally high (with the exception of the Stettler and Virgo pools whose large thicknesses compensate for lower porosities). During the course of the study, low porosities, typical of many light oil reservoirs in Alberta, were found to be a major limitation to steamflooding success.

As has been stated by many authors^{1,2,3,4}, it is impossible to make broad generalizations and determine that if certain criteria are met, success is guaranteed. Each reservoir must be considered on an individual basis. However, rough guidelines can be suggested.

based on reported steamflood field test results and on the simulation performed as part of this study.

The most important requirements for the success of a light oil steamflood are a large initial oil saturation and a high porosity. The porosity-oil saturation product at the start of the steamflood operation should be at least 0.10. Pay zone thickness is also an important factor in that heat losses to the overburden increase as the pay zone thickness decreases. It is felt that the oil zone thickness should be of the order of 6 meters (19.7 feet) or greater. Other important factors to consider include depth, reservoir pressure, and steam injectivity.

A significant portion of the expense involved in steamflooding is due to the high cost of generating steam. If sources of energy less expensive than oil are available for steam generation, the economics of a light oil steamflood become more attractive. Possible alternatives would be coal or geothermal energy.

The possibility for success of any steamflood operation would also be improved by keeping the heat losses at the surface and within the tubing as low as possible. Considerable work has been done to develop methods of reducing heat losses in steam injection operations. Insulated tubing has been used extensively to reduce heat losses in steam injection wells.¹¹ Downhole steam generators are also being developed which, if successful, would effectively eliminate the problem of wellbore heat losses. Most light oil reservoirs are relatively deep and thus wellbore heat loss reduction becomes extremely important.

CONCLUSIONS

Based on this study, the following conclusions may be drawn:

1. Many light oil reservoirs in Alberta are suitable for steamflooding.
2. The success of light oil steamflooding projects is strongly dependent on (i) initial oil saturation, (ii) formation porosity, and (iii) pay zone thickness. It is felt that the minimum porosity-oil saturation product should be 0.10 and that the pay zone thickness should be a minimum of about 6 meters.
3. Reduction of surface and tubing heat losses would improve the efficiency and the economic outlook of a light oil steamflooding operation.
4. Alternate energy sources for steam generation would make light oil steamflooding more economical.

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NOMENCLATURE

f_s = steam quality

n	= net pay thickness, m
h_t	= gross pay thickness, m
h_w	= enthalpy of water at steam temperature, kJ/kg
h_R	= enthalpy of water at reservoir temperature, kJ/kg
h_s	= enthalpy of saturated steam at steam temperature, kJ/kg
i_s	= rate of steam injection, m ³ /day
k_{hob}	= conductivity of the overburden, W/m-K
L_v	= latent heat of vaporization of saturated steam at steam temperature, kJ/kg
M_{ob}	= heat capacity of the overburden, kJ/m ³ K
M_s	= formation volumetric heat capacity, kJ/m ³ K
N_p	= cumulative oil production, m ³
P	= steam injection pressure, MPa
Q_i	= heat injection rate, kW
S_{oi}	= initial oil saturation, vol/vol
S_{orst}	= residual oil saturation to steam, vol/vol
t_c	= critical time, days
t_D	= dimensionless time
t_{Dc}	= dimensionless critical time
T_R	= reservoir temperature, °C
T_s	= steam temperature, °C
V_s	= steam zone volume, m ³
ϕ	= porosity, vol/vol

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Field, Location	Start Date	Visc, mPa-s	Por, vol/vol	Sol, vol/vol	$\phi \cdot \text{Sol}$	h, m	Depth, m	Result
East Coalinga, California	1963	100	0.34	0.51	0.1709	15.2	274-671	Successful
Bradford, Pennsylvania	1964	4	0.20	0.34	0.0680	?	?	Unsuccessful
Brea, California	1964	6	0.22	0.49	0.1078	57.6	1402	Successful
Smackover, Arkansas	1964	75	0.36	0.71	0.2556	6.1	610	Successful
El Dorado, Kansas	1965	4	0.26	0.40	0.1040	5.2	198	Unsuccessful
Franklin, Pennsylvania	1965	47	0.12	0.40	0.0480	21.3	137-183	Unsuccessful
Shamberg, Pennsylvania	1965	3	0.09	0.29	0.0261	13.1	274	Unsuccessful
Triumph, Pennsylvania	1965	5	0.10	0.19	0.0190	30.5	183-229	Unsuccessful
Shiells Canyon, California	1973	6	0.21	0.47	0.0987	48.8	259	Successful
Fyzabad, Trinidad	1974	35	0.34	0.66	0.2244	?	762	Too early to tell
Lacq Superieur, France	1977	17	0.15	0.75	0.1125	?	610	Promising
Lost Hills, California	1977	50	0.43	0.70	0.2975	?	366	Too early to tell
Buena Vista Hills, California	1981	5	0.30	0.33	0.0990	13.7	914	Not Known
Emerande, Congo	1982	100	0.25	0.90	0.2250	?	305	Not Known
Humble, Texas	1982	1	0.36	?	?	21.9	1189	Not Known

Table 2: Light Oil Steamflood Candidates

Pool	h avg, m	ϕ	Sol	$\phi \cdot \text{Sol}$	Simulation Result	BT Rec. (%)	OSR	Init.
Alderson, Upper Mannville Y	10.90	0.26	0.632	0.1643	Successful	58.52	0.1518	
Grand Forks, Upper Mannville B, WF	5.83	0.27	0.563	0.1519	Successful	57.14	0.1247	
Johosoa, Glauconitic B	8.82	0.25	0.737	0.1842	Successful	60.14	0.1701	
Majorville, Upper Mannville A	4.35	0.24	0.651	0.1563	Successful	58.18	0.1235	
Provost, Lloydminster A	7.70	0.22	0.626	0.1377	Successful	58.81	0.1212	
Provost, Lloydminster E	8.60	0.28	0.645	0.1805	Successful	58.41	0.1624	
Rainier, Glauconitic A	4.35	0.26	0.686	0.1784	Successful	58.72	0.1423	
Taber North, Glauconitic A	11.70	0.24	0.707	0.1698	Successful	59.41	0.1611	
Taber North, Glauconitic E	7.02	0.22	0.738	0.1623	Successful	59.36	0.1448	
Thompson Lake, Ellerslie A	5.24	0.27	0.645	0.1741	Successful	58.45	0.1435	
Enchant, Upper Mannville K	11.30	0.19	0.621	0.1181	Promising	58.18	0.1090	
Grand Forks, Sawtooth L	6.19	0.23	0.554	0.1274	Promising	56.83	0.1053	
Highvale, Baff H	10.46	0.19	0.550	0.1046	Promising	56.98	0.1029	
Leo, Upper Mannville A	12.20	0.20	0.535	0.1071	Promising	56.76	0.0966	
Little Bow, Upper Mannville P	4.47	0.21	0.624	0.1309	Promising	58.61	0.1035	
Pembina, Belly River J	9.60	0.20	0.517	0.1035	Promising	55.85	0.0901	
Sietler, Lower Mannville A	17.50	0.16	0.624	0.1000	Promising	58.21	0.0961	
Turin, Upper Mannville C	4.62	0.24	0.615	0.1477	Promising	57.80	0.1172	
Virgo, Keg River E3E	55.17	0.14	0.754	0.1026	Promising	60.70	0.1073	
Willasden Green, Second White Specks	10.80	0.22	0.477	0.1049	Promising	55.08	0.0999	

**Figure 1: Temperature Profile For
Injector to Producer Cross-Section.**
0.25 Pore Volumes of Steam Injected.

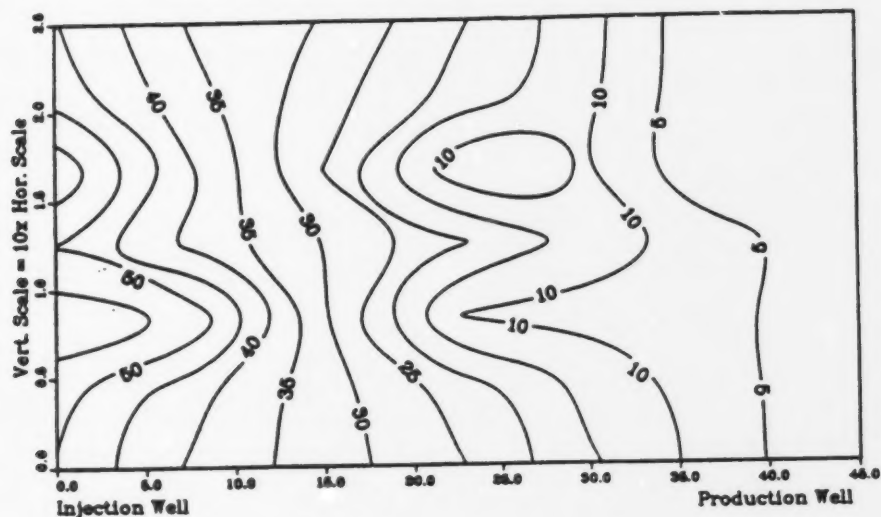


**Figure 2: Temperature Profile For
Injector to Producer Cross-Section.**
0.50 Pore Volumes of Steam Injected.

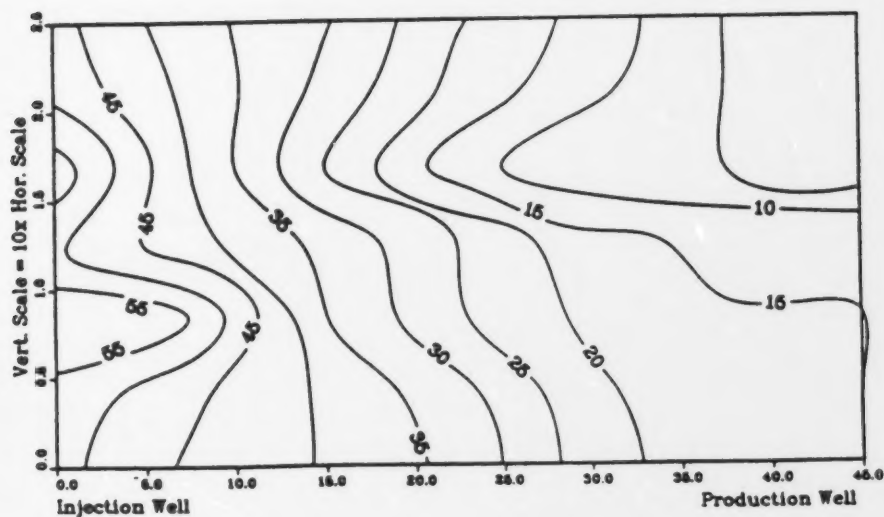


Figure 3: Temperature Profile For
Injector to Producer Cross-Section.
0.75 Pore Volumes of Steam Injected.

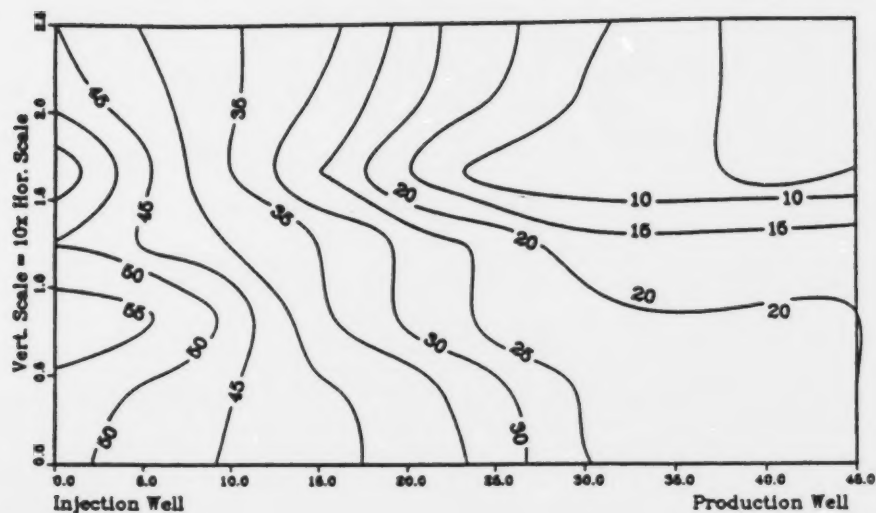
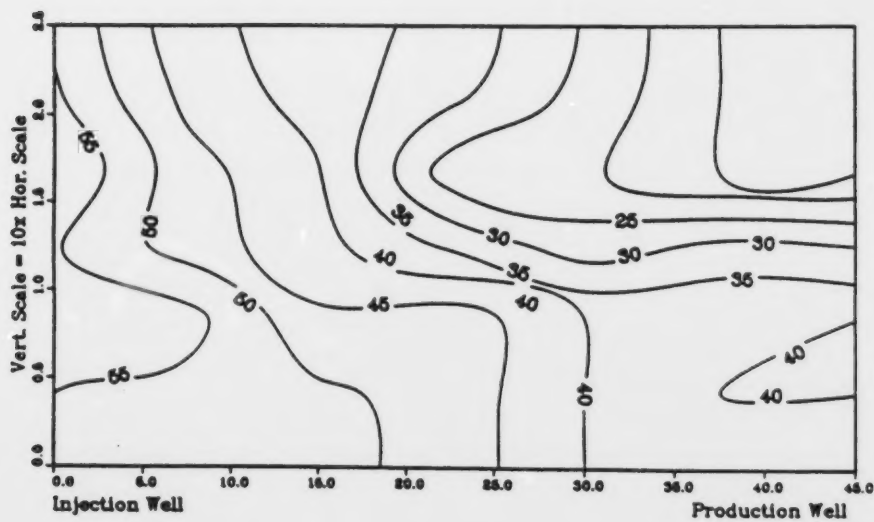


Figure 4: Temperature Profile For
Injector to Producer Cross-Section.
1.00 Pore Volumes of Steam Injected.



Appendix: Reservoirs Considered in this Study

Pool	Depth, m	h avg, m	Por.	Sol	Ø Sol	N*1000m ³	Np*1000m ³	A, hect.	Status
Acheson D-3 A Water flood	1547.8	24.12	0.105	0.290	0.0305	27600	16262.1	1542	Operating
Alderson, Lower Mannville C	985.1	11.40	0.17	0.543	0.0923	1460.0	112.7	128	GPP
Alderson, Upper Mannville Y	1032.9	10.90	0.26	0.632	0.1643	599.0	25.8	32	Operating
Bigoray, Nisku F Water Flood	2400.0	51.00	0.110	0.534	0.0587	2500	702.3	60	Operating
Bigoray, Nisku G Water Flood	2340.4	20.00	0.120	0.447	0.0537	750	159.5	55	Operating
Bigoray, Nisku H Water Flood	2290.3	46.00	0.120	0.628	0.0754	2200	187.9	58	Operating
Black, Keg River A Water Flood	1993.7	82.00	0.078	0.441	0.0344	2860	603.2	80	GPP
Bonnie Glen, D-3 A	2165.6	55.44	0.106	0.288	0.0305	125000	72215.1	3120	Operating
Brazzau River, Nisku A Solvent Flood	3107.4	73.20	0.110	0.406	0.0447	5300	1765.7	108	Operating
Brazzau River, Nisku B Water Flood	3070.1	68.80	0.058	0.509	0.0295	2300	471.5	90	Operating
Buffalo Lake D-3	1685.2	28.65	0.101	0.394	0.0398	1410	669.6	65	GPP
Buffalo Lake, D-3 B	1676.7	26.80	0.100	0.477	0.0477	782	232.5	43	Operating
Carson Creek N, Beaverhill Lake B WF	2662.7	14.68	0.089	0.329	0.0293	42500	14720.8	6453	Operating
Cherhill, Banff M	1324.2	15.78	0.140	0.518	0.0726	1890	57.8	160	Operating
Clareholm, Rundle A	2065.9	28.96	0.086	0.583	0.0501	1920	48.1	129	GPP
Countess, Upper Mannville H	1072.0	5.33	0.22	0.462	0.1015	5400.0	1811.9	663	GPP
Countess, Upper Mannville M	1079.9	14.02	0.23	0.430	0.0989	556.0	112.3	32	GPP
Crossfield, Rundle G	2601.8	12.19	0.102	0.438	0.0447	1230	130	202	Operating
Cyn-Pem, Rock Creek C & G	2177.4	10.25	0.104	0.457	0.0476	313	1	64	Operating
Drumheller, Mannville GG	1293.4	13.13	0.130	0.414	0.0538	909	5.3	128	Operating
Edson, Bluesky A	2567.0	13.94	0.100	0.599	0.0599	3800	56.6	448	Operating
Enchant, Upper Mannville K	1044.7	11.30	0.190	0.621	0.1181	856	2.1	64	Operating
Ferrier, Belly River B	1659.9	10.80	0.130	0.575	0.0747	522	2.7	64	Operating
Garrington, Lower Mannville E	2639.0	10.00	0.120	0.521	0.0625	403	2.7	64	GPP
Gilby, Basal Mannville R	2139.7	16.50	0.140	0.687	0.0962	1040	24.4	64	Operating
Gladys, Lower Mannville A	2056.9	22.39	0.120	0.518	0.0622	2710	36.8	192	GPP
Glen Park, D-3 A	1921.8	39.32	0.097	0.257	0.0249	4660	2967.3	173	Operating
Golden Spike, Gas Flood Area (DI)	1810.2	135.64	0.087	0.316	0.0275	49600	27619.1	590	Operating ?
Gordondale, Halfway B	1835.1	10.00	0.110	0.479	0.0527	687	13	128	Operating
Grand Forks, Sawtooth L	865.2	6.19	0.23	0.554	0.1274	805.0	48.0	96	GPP
Grand Forks, Upper Mannville B, WF	921.7	5.83	0.27	0.563	0.1519	2950.0	832.8	239	GPP
Hays, Lower Mannville A, WF	951.3	4.94	0.28	0.422	0.1182	3600.0	1345.3	386	Operating
Highvale, Banff H	1607.1	10.46	0.190	0.550	0.1046	4560	19.7	415	Operating
Homegren-Rimbe, D-3 B	2390.5	17.75	0.130	0.429	0.0558	1290	22.8	128	Prev. Conf
Hussar, Glauconitic A	1454.2	7.07	0.210	0.422	0.0886	6980	2750.1	675	Operating
Hussar, Glauconitic NNN	1393.4	12.00	0.150	0.530	0.0795	614	3.2	64	Operating
Innisfail, Belly River A	1298.5	12.70	0.150	0.474	0.0712	1740	5	192	Operating
Innisfail, Belly River C	1292.8	11.90	0.160	0.484	0.0775	590	0	64	Prev Conf.
Johnson, Glauconitic B	1832.3	8.82	0.25	0.737	0.1842	1320.0	20.5	80	Operating
Judy Creek, Beaverhill Lake A WF	2641.1	20.85	0.090	0.397	0.0358	130000	43409.3	11616	Operating
Judy Creek, Beaverhill Lake B WF	2695.0	19.54	0.092	0.398	0.0302	41300	14517.2	4538	Operating
Kaybob Nisku C	2541.5	36.00	0.072	0.659	0.0474	1100	7.5	64	GPP
Kaybob, Beaverhill Lake A WF	2980.9	18.29	0.074	0.334	0.0247	47700	14716.7	7288	Operating
Lanaway, Elkton A	2393.3	15.24	0.100	0.481	0.0481	481	4.2	65	Operating

Lanaway, Mannville E	2356.3	15.90	0.100	0.384	0.0384	391	0.4	64	Operating
Larne, Keg River C	1427.1	60.96	0.092	0.751	0.0691	718	44.3	16	Operating
Larne, Keg River V	1408.3	49.80	0.114	0.658	0.0751	2400	8	64	Prev. Conf
Lathom, Upper Mannville A, WF	1171.0	6.31	0.23	0.422	0.0971	4200.0	1590.0	426	GPP
Leduc-Woodbend, Blairmore E	1347.8	10.97	0.150	0.544	0.0816	605	23.3	65	GPP
Leduc-Woodbend, D-3 E	1634.6	10.67	0.090	0.615	0.0553	403	19.2	65	GPP
Leduc-Woodbend, D-3 F	1658.1	20.91	0.093	0.299	0.0278	1030	559.8	81	GPP
Leo, Upper Mannville A	1152.9	12.20	0.200	0.535	0.1071	843	7.1	64	Operating
Little Bow, Upper Mannville P	1131.9	4.47	0.21	0.624	0.1309	200.0	12.7	32	GPP
Majorville, Upper Mannville A	1378.6	4.35	0.24	0.651	0.1563	965.0	94.9	128	Operating
Medicine River, Basal Quartz J	2217.7	10.47	0.140	0.573	0.0802	556	18.3	64	GPP
Medicine River, Jurassic D	2141.2	14.11	0.145	0.475	0.0688	8140	1451	689	GPP
Mikwan, D-3 B	1819.5	13.00	0.120	0.617	0.0741	645	28.5	64	Operating
Minnehik-Buck Lake, Belly River G	1178.2	13.00	0.150	0.562	0.0843	704	2.5	64	Prev. Conf.
Nevis, D-3 C	1788.3	65.87	0.080	0.553	0.0443	222	47	6	GPP
Nevis, D-3 E	1832.5	45.81	0.120	0.616	0.0739	1270	118.4	34	GPP
New Norway, D-2	1425.2	18.70	0.085	0.300	0.0255	2150	1209.8	197	Operating
Pembina, Belly River J WF	1245.7	9.60	0.200	0.517	0.1035	1420	138.3	129	GPP
Pembina, Belly River TTT	1046.7	10.00	0.210	0.424	0.0890	1150	11.3	128	Operating
Pembina, Nisku K Solvent Flood	2886.1	73.30	0.104	0.432	0.0450	2430	518.2	58	Operating
Pembina, Nisku L Water Flood	2869.7	30.10	0.105	0.527	0.0554	5000	784.4	253	Operating
Pembina, Nisku P Solvent Flood	2905.0	44.00	0.103	0.492	0.0507	4250	457.4	170	Operating
Pine North-West, Second White Specks A	1845.6	7.62	0.150	0.550	0.0825	415	6.5	65	GPP
Progress, Halfway B	1882.7	12.80	0.090	0.528	0.0475	2350	13.6	384	Operating
Provost, Lloydminster A	805.1	7.70	0.220	0.626	0.1377	684	5.6	64	GPP
Provost, Lloydminster E	775.5	8.60	0.280	0.645	0.1805	498	1.3	32	Prev. Conf.
Rainbow South, Keg River A WF	1945.2	65.17	0.097	0.388	0.0376	5720	1623.5	167	GPP
Rainbow South, Keg River E WF	1964.1	92.57	0.075	0.411	0.0308	7150	2101.3	177	GPP
Rainbow South, Keg River J	1941.6	19.40	0.138	0.613	0.0846	514	21.6	30	Operating
Rainbow, Keg River EEE Solvent Flood	1855.3	64.01	0.168	0.473	0.0794	1910	690.4	24	I.S. No. 1
Rainbow, Keg River II Solvent Flood	1812.0	71.48	0.100	0.354	0.0354	3490	1642.7	73	Operating
Rainier, Glauconitic A	1032.0	4.35	0.26	0.686	0.1784	261.0	12.7	32	Operating
Red Earth, Granite Wash C	1460.9	11.90	0.134	0.526	0.0705	2640	619.1	241	Operating
Redwater D-3	977.8	31.39	0.065	0.255	0.0166	207000	128000	15199	GPP
Redlaw, Mannville TT	1082.5	14.88	0.134	0.512	0.0686	1310	2.8	128	GPP
Rich, D-3 A	1796.3	103.00	0.120	0.723	0.0867	6190	471.7	64	Operating
Ricinus, Cardium B	2732.0	11.34	0.170	0.413	0.0703	600	66.2	67	GPP
Ricinus, Cardium F	1810.5	23.90	0.100	0.595	0.0595	950	40.5	64	GPP
Ricinus, Cardium L	2320.9	8.10	0.130	0.599	0.0779	5000	430.3	724	Operating
Ricinus, Cardium S	2325.9	15.51	0.150	0.518	0.0777	814	30.2	65	Operating
Ricinus, Cardium W	2192.8	17.00	0.150	0.632	0.0948	4290	166.2	256	Operating
Shekille, Keg River A	1699.3	67.06	0.094	0.467	0.0439	504	121.5	13	Operating
Shekille, Keg River F	1748.0	113.39	0.073	0.468	0.0342	238	44.3	5	Operating
Shekille, Keg River M	1789.5	94.00	0.100	0.651	0.0651	700	26.8	11	GPP
St. Albert-Big Lake, D-3 A	1463.6	43.24	0.110	0.333	0.0366	3700	2101.6	101	GPP

Appendix: Reservoirs Considered in this Study

Stettler, Lower Mannville A	1319.8	17.37	0.160	0.624	0.0998	1110	0.5	64	Operating
Sylvan Lake, Jurassic C	2242.5	10.50	0.130	0.593	0.0771	1590	36.1	192	GPP
Sylvan Lake, Second White Specks A	2086.0	12.00	0.180	0.349	0.0627	484	2.2	64	GPP
Taber North, Glauconitic A	948.5	11.70	0.24	0.707	0.1698	8000.0	333.5	386	Operating
Taber North, Glauconitic E	951.0	7.02	0.22	0.738	0.1623	742.0	12.7	64	Operating
Tehze, Sulphur Point A	1739.3	17.37	0.112	0.686	0.0768	604	56.7	41	Operating
Thompson Lake, Ellerslie A	980.1	5.24	0.270	0.645	0.1741	1050	28.3	112	Operating
Thorby, Glauconitic A	1489.9	21.90	0.120	0.513	0.0615	3520	69.8	256	Operating
Trochu, Basal Quartz A	1479.4	15.41	0.200	0.456	0.0913	922	21.8	64	GPP
Turin, Upper Mannville C	1000.7	4.62	0.24	0.615	0.1477	2060.0	149.4	280	Operating
Turner Valley, Blairmore A&B	1363.4	16.76	0.117	0.635	0.0743	815	5.3	65	GPP
Turner Valley, Rundle Water Flood	2557.0	47.55	0.082	0.521	0.0428	159000	21523.4	6763	GPP
Valhalla, Doe Creek I	718.7	4.18	0.230	0.147	0.0337	29700	226	20912	Operating
Virgo, Keg River E	1513.0	66.96	0.094	0.508	0.0478	620	204.1	13	Operating
Virgo, Keg River E3E	1471.6	55.17	0.136	0.754	0.1026	556	46.6	9	GPP
Virgo, Keg River X2X	1476.5	49.07	0.105	0.610	0.0640	397	51.5	11	GPP
Wayne-Rosedale, Basal Quartz DD	1360.9	11.00	0.150	0.518	0.0777	549	1.8	64	GPP
Wayne-Rosedale, Basal Quartz PP	1288.5	12.00	0.140	0.407	0.0570	441	3.2	64	Operating
Wayne-Rosedale, Upper Mannville E	1437.3	14.00	0.140	0.558	0.0781	351	1.2	32	GPP
Westerose D-3	2204.6	72.20	0.105	0.278	0.0291	31000	17279.9	652	Operating
WestPem, Nisku C Solvent Flood	3033.0	90.35	0.110	0.541	0.0596	4000	771.2	60	Operating
Williesden Green, Second White Specks B	2082.0	10.80	0.220	0.477	0.1049	730	5.1	64	GPP
Wizard Lake, D-3 A Solvent Flood	1969.0	86.13	0.096	0.171	0.0164	62000	46771.2	1075	Operating
Youngstown, Ates	1132.0	10.40	0.103	0.618	0.0636	1870	275.8	241	GPP
Zama, Keg River T4T	1547.5	88.70	0.075	0.465	0.0349	318	101.5	7	GPP
Zama, Keg River W3W Water Flood	1520.3	73.00	0.139	0.533	0.0741	524	145.1	7	GPP

Steam Injection Experiments in a Scaled Model for a Marginal Reservoir

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Abstract

Scaled physical models of steamflooding processes are of great value in designing a steamflood and obtaining insight into the process mechanics. As such, they complement numerical simulation. In fact, numerical simulators can often be validated on the basis of a scaled model.

The paper discusses the design and operation of a scaled model of the low pressure type. This model was employed for 37 steamflood experiments which were conducted under a wide variety of conditions and examined numerous operating strategies. The primary objective of these runs was to examine ways of steamflooding thin reservoirs (6 - 13 meters), with underlying bottom water in many cases. The oil viscosity simulated in most experiments was 1275 mPa·s, which is typical of many thin, heavy oil reservoirs in Saskatchewan and Alberta. The experiments carried out included: steamfloods after a waterflood, steamfloods in bottom water situations, waterflood following the injection of a steam slug, gas injection in bottom water situations in which a small volume of gas was injected into the upper part of the pack prior to steam injection, and steamflood experiments utilizing horizontal wells. The model was also used to examine the recovery potential of watered out, light oil reservoirs.

Several steam injection strategies tested yielded favourable results. A cold waterflood following a steam slug generally gave a higher oil recovery than continuous steam injection (e.g. 30.5% vs. 28.5%). Horizontal well runs were also efficient, although it is questionable whether a horizontal well can be drilled successfully in a thin formation. Gas injection prior to steamflooding

also produced interesting results and may be a viable method of recovering heavy oil from thin, bottom water reservoirs, under some conditions.

Introduction

Models (both physical and numerical) have been used to gain a better understanding of the physical processes involved in steamflood operations. Models have also been extensively employed as predictive tools to help design the best recovery program for a particular field.

A wide variety of experiments have been conducted in physical models to examine thermal recovery processes. These include core steamflood studies which investigated relevant operating parameters such as steam injection rate and pressure, steam quality, and reservoir thickness, to name a few. A few steam injection studies have been conducted in laboratory models to examine recovery from reservoirs with specific attributes such as bottom water, gas caps, shale breaks, extremely high oil viscosity, or with substantial waterflood residual oil saturation.

Physical models representing prototype reservoirs can be of three types: (1) scaled, (2) partially scaled, or (3) unscaled. The great majority of physical models have been of the unscaled variety but, although such models are useful in obtaining qualitative information on specific recovery mechanisms, they do not provide nearly as much quantitative information as scaled physical models.

The research addressed by this paper involved scaled model experiments of steamflooding operations in marginal reservoirs and utilized a scaled model of the low pressure variety, based on Stegemeier, Laumbach, and Volek's¹ scaling criteria. The apparatus used in this work was designed to represent one-quarter of an eight hectare (twenty acre) five-spot pattern. A number of experiments were carried out to show the use of the apparatus and to examine the efficacy of the processes under investigation.

The main target of the experimental studies was the Aberfeldy heavy oil reservoir of the Lloydminster, Saskatchewan area. The reservoir is characterized by viscous oil (1275 mPa·s at reservoir temperature) and thin pay (6 to 13 meters), with bottom water present in many areas. Reservoirs of this type are common in Saskatchewan and eastern Alberta; thus it is imperative to develop recovery strategies which are likely to succeed in the field.

Scaled Model Studies of Steam Injection Processes

A model which could accurately predict the production response of a reservoir under steam stimulation would be highly desirable. With an accurately scaled model, numerous strategies can be examined and optimized before implementing the full scale operation in the prototype.

Farouq Ali and Redford² presented a comprehensive review of the approaches used in scaling steam injection processes. They state that the design of a scaled physical model is based on the Principle of Similarity* and is characterized by the same ratios of dimensions, forces, velocities, temperature differences, and concentration differences as those occurring in the prototype. In general, two types of scaling methods can be used to model thermal recovery processes: (1) high pressure and (2) low pressure (or vacuum).

There have been several notable studies dealing with high pressure scaled models. Geertsma, Croes, and Schwarz⁴ derived the dimensionless groups for scaling crude oil displacement processes including the injection of hot water. Pujol and Boberg⁵ developed scaling criteria applicable to high pressure steam injection. Their scaling criteria has been applied in several notable experimental efforts including the work of Pursley⁶, Ehrlich⁷, Huygen⁸, Huygen and Lowry⁹, Singhal¹⁰, and Lo¹¹. Kimber, Farouq Ali, and Puttagunta¹² developed several sets of scaling criteria for high pressure models, including one which allows the model to use the same porous media and fluids as the prototype reservoir, but requires that the geometric scaling be relaxed in the vertical dimension. Other

*Farouq Ali and Redford refer the readers to a book by Johnstone and Thring³ for a discussion of the Principle of Similarity.

noteworthy studies which deal with high pressure model scaling criteria include the work of Perkins and Collins¹³, Demetre, Bentsen, and Flock¹⁴, Greenkorn¹⁵, Loomis and Crowell¹⁶, Bentsen¹⁷, Rapoport¹⁸, and Leverett, Lewis, and True¹⁹.

Scaled physical models of steam injection, for low pressure (vacuum) operation were first proposed by Stegemeier, Laumbach, and Volek¹. They demonstrated that materials differing from those found in the prototype reservoir can be used in the vacuum model system and that such a model can accurately predict field response. Prats²⁰ conducted numerous low pressure scaled model experiments designed to examine the recovery potential of the Peace River oil sand deposit. Doscher²¹ constructed a vacuum model based on the scaling criteria developed by Stegemeier et. al.¹ He developed scaling parameters from similarities in an integral form, based on a study by Yortsos²², rather than a differential form as used by Stegemeier et. al.¹ Doscher and Huang²³ and Doscher and Ghassemi²⁴ used this model for additional studies.

Research on Thin, Bottom Water Reservoirs

Kasraie and Farouq Ali²⁵ examined the mechanisms involved in thermal stimulation of bottom water reservoirs. Based on their survey of existing field and laboratory data, the authors concluded that a water zone thicker than about one-fifth of the oil zone would make cyclic steam stimulation uneconomical.

The Peace River reservoirs, modeled by Prats²⁰ contained a substantial oil saturation (45%) in conjunction with the bottom water layer; thus injection into the mobile bottom water zone still produced an economically acceptable amount of oil. The Cold Lake reservoir studied by Pursley⁶ had a pay thickness of 43 meters (140 feet) and the Wabasca reservoir studied by Huygen and Lowry⁹ had a thin bottom water zone relative to the total pay thickness, and both have viscosities of the order of 10^5 mPa·s. Thus, the results of these studies are not representative of thin, bottom water reservoirs such as the Aberfeldy reservoir.

A numerical simulation study was performed by Singh, Malcolm, and Heidrick²⁶ with the objective of evaluating the potential for steam injection and steam injection with additives in reservoirs with bottom water. The project encompassed a number of numerical simulations which were run to determine the effects of bottom water thickness, carbon-dioxide injected along with the steam, blocking agents, and injection-production strategy. The results given were of a very general nature, and did not give any definite guidelines for producing bottom water reservoirs.

The Complementary Roles of Numerical Simulation and Scaled Physical Models

Numerical simulation of steam injection processes is at a stage where simpler situations can be simulated. The principal limitations are (1) the grid size, which limits simulation to that of an element of symmetry of a pattern, and that too, with limited definition; and (2) process representation, which means that some of the processes involved in thermal stimulation are still unclear, particularly the rock-fluid interactions. Often, unrealistic assumptions are put into a simulator to obtain a history match; for example, using a rock compressibility factor which is several orders of magnitude higher than the real compressibility ('spongy rock effect'²⁷) to compensate for a parameter which is not implemented (or possibly not understood).

In spite of these deficiencies, numerical simulators can be valuable tools to complement physical model studies. They can provide fast predictions which may be used to assess the relative role of variables in a given steam process. With adequate information available for history matching, numerical models may be modified to provide accurate predictions of reservoir response to changes in operational strategy, thus limiting the need for physical models. However, if production data is limited or nonexistent, the use of a numerical simulator in conjunction with a scaled physical model would provide the most reliable prediction.

Experimental Apparatus and Procedure

The apparatus used in this study was designed based on the low pressure scaling criteria. One of the first steps in designing a physical model to simulate a field system is to determine the characteristics to be used to describe the prototype reservoir. The values listed in Table 1 were chosen to represent the Aberfeldy prototype.

The model was designed to represent one-quarter of an eight hectare (twenty acre) five-spot pattern, and as such, has one injection well and one production well at diagonally opposite corners. The size of the model is limited in that it must be of a size suitable for a laboratory, and that the experimental run time must not be prohibitive. With these constraints, the model was chosen to be 81.3 cm (32 in.) square and 6.4 cm (2.5 in.) thick. This produces a geometric scaling factor of 173.2.

The scaled model operating parameters were calculated in the manner described by Stegemeier et. al.¹. The operating parameters for the Aberfeldy scaled model are summarized in Table 2. Note that the time scale is 12.18 minutes in the model for each year in the prototype, thus a great deal of data is produced in a very short time during an experimental run.

A schematic diagram of the apparatus used in this research is presented as Figure 1. The main components of the apparatus are the physical model, the steam injection system, the model cart and cold storage unit, the fluid collection system, and the data acquisition system. A brief description of each of these main components of the apparatus is given below. A more detailed description of the apparatus along with the names and addresses of many of the equipment suppliers is contained in Reference 28.

Fiberglass was chosen as the model material because it has a relatively low heat transfer coefficient, it is inexpensive to fabricate, it is relatively easy to machine, and it can be constructed to be capable of withstanding the severe loading induced on the model as a result of the vacuum scaling

requirements. The high permeability required by the scaling criteria was achieved by using glass beads with a diameter of approximately three millimeters (6-8 mesh). The cap and base rocks of the model consisted of granite blocks, which closely modeled the heat transfer between the cap and base rocks of the actual reservoir.

Important components of the model were the injection and production wells. These were constructed out of aluminum rod and set into diagonally opposite corners of the molded fiberglass model. The wells were designed according to the slot well method described by Stegemeier et. al.¹, which resulted in a model well slit of 0.1088 inches representing a prototype well with a six inch diameter. The wells were designed to allow a gate device to be inserted into them, which enabled the experimenter to selectively choose the injection and production intervals.

The boiler system consisted of an insulated oil bath containing eight fire rods which heated the bath quickly and uniformly at a rate determined by an electronic temperature controller. Water passed through an eighty foot length of coiled, stainless steel tubing contained in this hot oil bath. This boiler system was set up to produce a superheated steam at 120°C which was mixed with a stream of room temperature water to produce a steam quality of 70%. Controlled volume pumps were used to pump de-aired, distilled water to the steam generator and to the water-steam mixing point.

A unique design was employed in the construction of many components of the experimental apparatus and the model support cart is a good example of this. A shaft was welded into the support area for the model and this shaft was connected by a rack and pinion to a gear box. This gear box imparted a tremendous mechanical advantage so that the entire 2000 kg model apparatus could be rotated with ease to improve the efficiency of the saturation process and to allow the simulation of dipping reservoirs for future experiments. A walk-in cooler was used to cool the model to the initial temperature of 30°C as required by the scaling groups. The model cart was set on castors which rolled on tracks to facilitate the movement of the model in and out of the cold storage room.

Operating the experiments under vacuum conditions introduces special considerations into the design of a collection system. The pore volume of the model was too large to allow the use of a single container to collect the produced fluids and very little information could be obtained from a single sample. Therefore, the system used two 2000 ml flasks to collect the produced fluids, which were arranged so that they could be isolated from the vacuum and emptied individually. Because the vacuum was applied through the collection system, it was expected that some vaporization of the produced fluids would occur. For this reason, the collection system included a series of condensers and cold traps to collect and retain all of the produced fluids.

Thirty-one thermocouples were placed in two layers within the model at strategic points for the purpose of recording the heat fronts through the model. Figure 2 schematically illustrates the thermocouple positions within the model. Other thermocouples and several pressure transducers were also placed throughout the system. A MEGADAC 2000 data acquisition system, from OPTIM Electronics Corporation was used to collect data during the experimental runs. The MEGADAC was controlled by an IBM PC and was programmed to scan each thermocouple and pressure transducer once every thirty seconds.

Due to the size and shape of the model, packing methods such as tamping or vibrating are not practical. Therefore a particle distributor was constructed and used to pack the glass beads within the model. This method of packing was first proposed by Currie and Gregory²⁹ and later modified by Wygal³⁰.

After packing the model with glass beads, a Teflon sheet was placed above the model and a thin layer of silicone was applied between the Teflon sheet and the fiberglass model to provide a vacuum tight seal. A rubber sheet was placed above the Teflon sheet to ensure that complete contact was made between the porous media and the upper granite block, which was then set in place above the model. The entire model was then tilted to facilitate the saturation process.

Six large saturation ports were incorporated into the model (three on each of two opposite sides) to improve the efficiency of the saturation process. With the apparatus in a tilted position, the fluids entered the model from the downdip end and thus the fluid flow into the model proceeded with a gravity stabilized front. To begin the saturation process, a vacuum was applied at the updip end and de-aired, distilled water was pulled into the model through the saturation ports at the downdip end. This continued until the model was completely saturated with water. The amount of water taken up during this saturation process was carefully measured and the model porosity was calculated using this water volume. Next, oil was drawn into the model by a method similar to that described for the water, which brought the model to irreducible water saturation. After saturation was complete, the apparatus was rolled into the cooler where it was left until it reached the low initial temperature required by the scaling groups.

For bottom water experiments, the saturation procedure was necessarily different. The water layer was established in the model by packing the model with just enough beads to cover the volume of water required to obtain the desired bottom water thickness. The beads and water were then frozen in place. With the bottom water layer frozen in place, the model was saturated in a manner similar to that described previously for the homogeneous packs. An innovative approach was used to determine the volume of bottom water that had thawed and been displaced during the saturation process. The bottom water layer was made up of a 5% solution of NaCl, and by measuring the refractive index of this solution, distilled water, and the sample displaced during saturation, the volume of bottom water remaining in the model after saturation could be determined. By the same method, the volume of bottom water produced during the steamflood experiment could also be determined.

With all of the necessary preparations complete, the model was rolled out of the cooler and all thermocouple and pressure transducer leads were connected, the injection and production lines were attached, and the data acquisition unit was reset for a new experiment. During the experiment, the production flasks were emptied into a series of 2000 ml graduated cylinders where instantaneous oil

and water recovery could be observed as a function of each two litres of total production. Steam injection was continued until one and one half to two pore volumes had been injected.

Discussion of the Results

The scaled physical model described in this paper has been employed for 37 steamfloods of various types. Table 3 lists the types of experiments which have been conducted along with information concerning the initial model conditions and the experimental results. It can be seen that the vacuum scaled model is capable of representing a large variety of situations and enables one to experiment with numerous steamflooding strategies.

Numerous experiments were conducted on a scaled model simulating the Aberfeldy reservoir of Saskatchewan. These included continuous steamfloods, steamfloods following a waterflood, steam slug runs which involved the injection of a small slug of steam followed by a waterflood, steamfloods in a bottom water model, steamfloods following the injection of a small volume of an inert gas in bottom water models and steamfloods utilizing horizontal wells.

Steam Slug A few of the recovery schemes gave good results. For the models without bottom water, it was found that the steam slug process, which involved injecting a small volume of steam followed by a waterflood, gave recoveries which were generally higher than continuous steam injection. Figure 3 gives a comparison of the recovery response for typical continuous steamflood and steam slug runs. It can be seen that the oil production from the steam slug process is higher for all values of cumulative production, and thus, is the most favourable process. It should also be noted that both processes appear to approach the same ultimate recovery.

Gas Injection Another injection process, which may be suitable for recovering oil from reservoirs underlain by bottom water, involves injecting a small volume of inert gas into the reservoir prior to steam injection. This strategy has the advantage of dramatically improving steam injectivity and thus it may be suitable for reservoirs where the desired steam injectivity cannot be achieved. Figure 4

compares the production response for continuous steam injection and steam injection following gas injection in a homogeneous model. It can be seen that the production response of the gas injection process is slightly lower than that of the continuous steam injection process. However, in a reservoir where steam injectivity is a problem, the injectivity improvement obtained by gas injection may justify the small decrease in oil recovery .

Bottom Water Steam injected into reservoirs underlain by bottom water often channels directly into the bottom water zone, thus drastically reducing the effectiveness of the process. It is hypothesized that by injecting an inert gas prior to steam injection, a flow channel away from the bottom water will be created for the steam, thus reducing the often detrimental effect of the bottom water. A few experiments have been conducted to test this hypothesis. Figure 5 presents a production response comparison between a continuous steam injection experiment and an experiment involving gas injection prior to steamflooding, in a bottom water model. It can be seen that the ultimate recovery of the gas injection process may be slightly higher than that of the continuous injection process. However, it can also be seen that for any given volume injected, up to about two pore volumes, the continuous steamflooding strategy gives a better oil production response. Only a limited number of experiments of this type have been conducted, and thus, it is too early to draw any conclusions about the gas injection process. However, it does appear to warrant further investigation.

Horizontal Wells The possibility of utilizing horizontal wells to recover oil from thin reservoirs was also investigated. Two steamflooding experiments employing a horizontal injector and producer, as well as an experiment employing a vertical injector and a horizontal producer were conducted. Based on these three experiments, a combination of vertical injectors and horizontal producers would appear to be the best arrangement for thin reservoirs. Figure 6 compares the recovery response of a continuous steamflood utilizing vertical wells and a continuous steamflood utilizing a horizontal production well. It can be seen that the production response for the vertical injector/horizontal producer system is slightly better than that for the vertical injector/vertical producer system. It should

be noted that the vertical injector for the horizontal well experiment was in the corner of the model, thus the pattern sweep efficiency was much poorer than would be obtained for a more optimal placement of the injection well. Overall, the recovery response of a steamflood utilizing a horizontal producer was excellent, however, the difficulty in placing a horizontal well in a thin reservoir may limit the viability of the process.

Light Oils In addition to the experiments conducted on the Aberfeldy type scaled model, experiments were conducted on models simulating reservoirs containing a lighter oil (25.6 mPa·s at reservoir conditions) and a heavier oil (13000 mPa·s at reservoir conditions) than the Aberfeldy prototype. The experiments conducted on the light oil models produced excellent results which prompted Proctor and Farouq Ali³¹ to conduct a study to examine the feasibility of steamflooding light and moderately viscous oil reservoirs in Alberta. The study indicated that several of Alberta's light oil reservoirs may be suitable for steamflooding, and that steamflooding may be an efficient means of recovering waterflood residual oil.

Conclusions

1. A low pressure, scaled steamflood apparatus was designed, constructed, and employed for numerous steamflood experiments and was found to be satisfactory for the purpose of conducting steamflood experiments.
2. The low pressure scaled model is capable of modeling a wide variety of steamflooding strategies. Experiments conducted in this study included continuous steamfloods, steamfloods following a waterflood, steam slug runs which involved the injection of a small slug of steam followed by a waterflood, steamfloods in a bottom water model, steamfloods following the injection of a small volume of an inert gas in bottom water models and steamfloods utilizing horizontal wells.
3. With no bottom water present, the steam slug process may be the most efficient and economically viable strategy for recovering oil from the thin, heavy oil formations typical of eastern Alberta and Saskatchewan.

4. In reservoirs underlain by water, gas injection prior to steamflooding may be a valid method for diverting steam from the bottom water zone.

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Table 1: Prototype Reservoir Data

Net Pay Thickness:	11 m
Porosity:	0.31
Permeability:	2000 md
Thermal Conductivity:	0.002077 KW/mK (1.2 Btu/hr ft F)
Heat Capacity:	2.2217 KJ/Kg K
Initial Saturation:	So=0.75, Sg=0.02, Sw=0.23
Steamflood Residual Oil Saturation:	Sor=0.15
Oil Viscosity:	1275 mPa-s at 23.9 C
Water Viscosity:	0.891 mPa-s at 25.8 C
Initial Reservoir Temperature:	23.3 C
Steam Injection Pressure:	1.900 MPa
Steam Injection Rate:	100-150 m3/day
Steam Quality:	0.70 (Actually is 0.80 but a lower value was chosen to allow for wellbore heat losses.)

Table 2. Summary of the Scaling Calculations for the Aberfeldy Model

Length Scale:	$\gamma(L) = L_p/L_m = 173.2$
Pressure Relation:	$P_m = 0.004683 + 0.006415 P_p$ (MPa)
Temperature Relation:	$T_m = 0.286 T_p - 3.657$ (°C)
Time Scale:	$t_m/t_p = 12.18$ minutes/year
Permeability:	prototype = 2 darcies model = 4216.5 darcies
Injection and Production Rate Scales:	$w_m/w_p = 9.0728$ (cm ³ /min)/(m ³ /day)
Initial Model Temperature:	3°C
Model Pressure:	Production end: 7 KPa (1 psia) Injection end: Near atmospheric pressure.

Table 3: List of Experiments

Run #	Model Type	Process	Special Features	Pressure (%)	Swi (%)	Cum. Prod. (NOOD)	Cum. PV Inj.
1	Heterogeneous Model	Preliminary Experiment	Water saturated model.	-	0.00	NA	NA
2	Heterogeneous Model	Preliminary Experiment	Water saturated model.	-	0.00	NA	NA
3	Heterogeneous Model	Preliminary Experiment	Water saturated model.	-	0.00	NA	NA
4	Heterogeneous Model	Continuous Steamflood	Water saturated model.	32.40	0.00	NA	0.4800
5	Heterogeneous Model	Continuous Steamflood		33.80	13.26	6.59	2.3400
6	Heterogeneous Model	Continuous Steamflood		33.30	15.51	21.89	1.1720
7	Heterogeneous Model	Continuous Steamflood		31.00	84.48	22.52	1.6750
8	Heterogeneous Model	Cold Waterflood		31.00	90.41	26.47	2.8670
9	Heterogeneous Model	Room Temperature Waterflood		31.00	-	32.40	NA
10	Heterogeneous Model	Continuous Steamflood	Heavy oil experiment (13000cup).	35.90	NA	NA	1.0100
11	Heterogeneous Model	Unsuccessful Run	Heavy oil experiment (13000cup).	32.90	87.68	12.32	2.1140
12	Heterogeneous Model	Continuous Steamflood		30.30	92.60	9.00	NA
13	Heterogeneous Model	Continuous Steamflood	Light oil experiment (25.6cp).	30.80	85.28	14.72	1.4356
14	Heterogeneous Model	Unsuccessful Run (Vacuum Leak)	Light oil experiment (25.6cp).	33.30	89.22	10.78	1.6524
15	Heterogeneous Model	Continuous Steamflood	Light oil experiment (25.6cp).	30.10	92.18	7.82	NA
16	Heterogeneous Model	Continuous Steamflood		33.10	90.22	9.78	1.2100
17	Heterogeneous Model	Unsuccessful Run (Vacuum Leak)		35.90	87.7 (avg.)	12.3 (avg.)	NA
18	Heterogeneous Model	Continuous Steamflood		32.40	93.47	6.53	NA
19	Heterogeneous Model	Unsuccessful Run (Vacuum Leak)		32.90	92.62	7.38	1.0310
20	Heterogeneous Model	Waterflood Following a Steam Slug		33.00	92.00	8.00	1.4440
21	Heterogeneous Model	Waterflood Following a Steam Slug		33.30	91.52	8.48	1.5600
22	Heterogeneous Model	Waterflood Following a Steam Slug		32.10	93.41	6.50	NA
23	Heterogeneous Model	Unsuccessful Run (Prod. Well Plugging)		32.50	94.36	5.64	NA
24	Heterogeneous Model	Hot Waterflood		34.10	89.45	10.55	1.3540
25	Heterogeneous Model	Continuous Steamflood	Improved saturation technique.	33.09	89.53	10.47	2.1072
26	Heterogeneous Model	Gas Injection Prior to Steamflood.		33.52	94.03	5.97	1.8548
27	Heterogeneous Model	Gas Injection Prior to Steamflood.	Injection into upper portion of model.	33.34	94.68	5.32	1.8533
28	Heterogeneous Model	Continuous Steamflood	Injection into lower portion of model.	33.46	94.77	5.23	1.9719
29	Heterogeneous Model	Continuous Steamflood		33.29	95.10	4.90	2.2313
30	Heterogeneous Model	Continuous Steamflood	Run spoiled by damaged boiler.	32.65	92.53	7.47	NA
31	Heterogeneous Model	Gas Injection Prior to Steamflood.		33.50	89.41	10.59	1.9200
32	Heterogeneous Model	Gas Injection Prior to Steamflood.	Injection into upper portion of model.	36.09	75.96 (avg.)	24.04 (avg.)	2.2296
33	Heterogeneous Model	Gas Injection Prior to Steamflood.	Saline B.W. (8000cc). Inj-t, Prod-t.	36.66	80.77 (avg.)	10.23 (avg.)	1.8406
34	Heterogeneous Model	Continuous Steamflood	Saline B.W. (6000cc). Inj-t, Prod-t.	34.01	95.36 (avg.)	4.64 (avg.)	1.8712
35	Heterogeneous Model	Continuous Steamflood	Inj into lower portion of model.	37.33	86.70 (avg.)	13.30 (avg.)	1.7582
36	Heterogeneous Model	Continuous Steamflood	Horizontal Inj. and Prod. well.	32.76	93.64	6.36	1.9800
37	Heterogeneous Model	Horizontal Well	Prod. well horizontal, Inj. well.	33.47	91.36	8.64	1.8055
38	Heterogeneous Model	Horizontal Well	Inj. and Prod. well horizontal.	34.00	90.44	9.56	1.7840
39	Heterogeneous Model	Gas Injection Prior to Steamflood.	Inj. into top, prod. over entire int.	36.07	85.25 (avg.)	14.75 (avg.)	1.9805

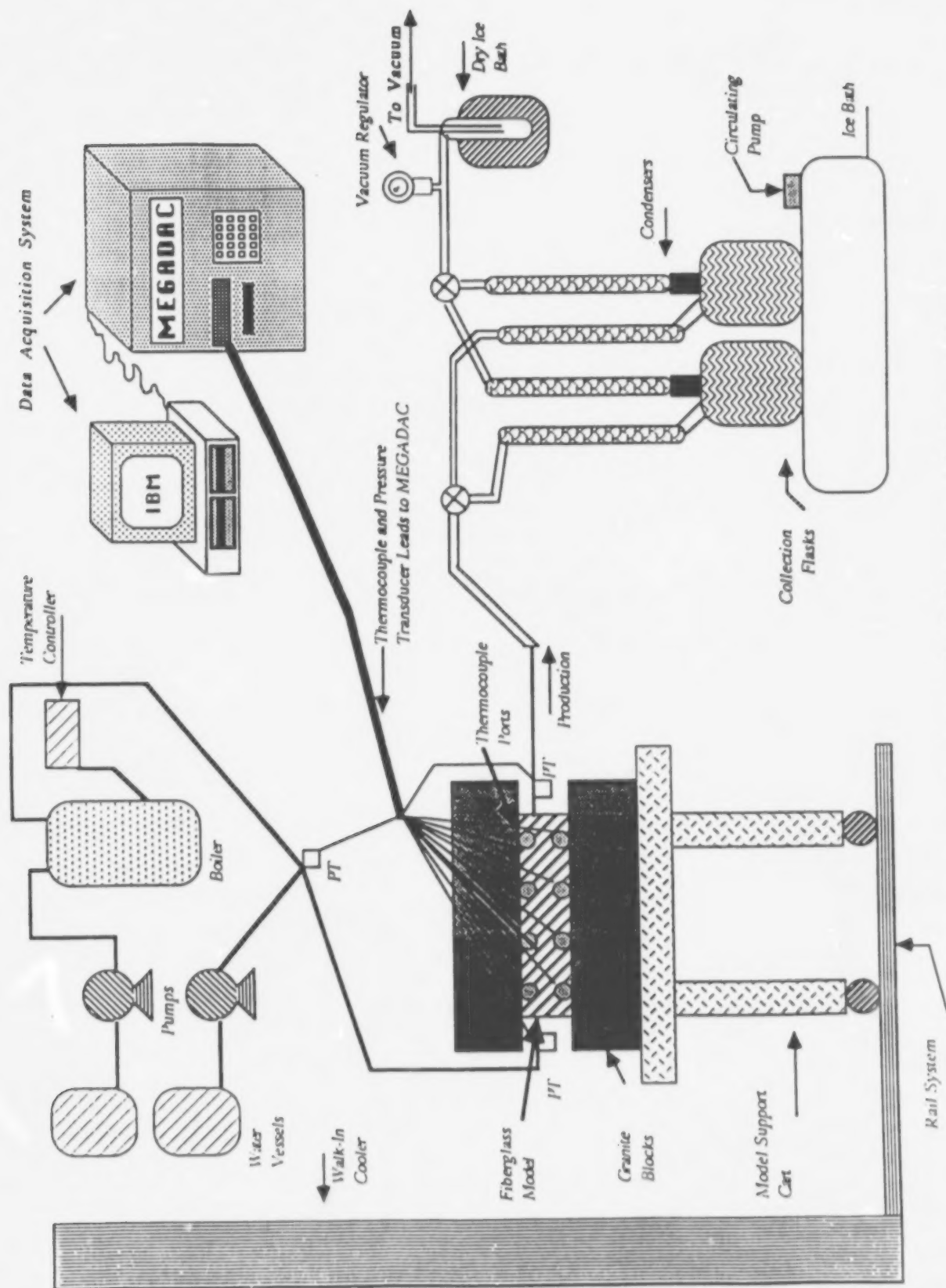


Figure 1. Schematic Diagram of Apparatus

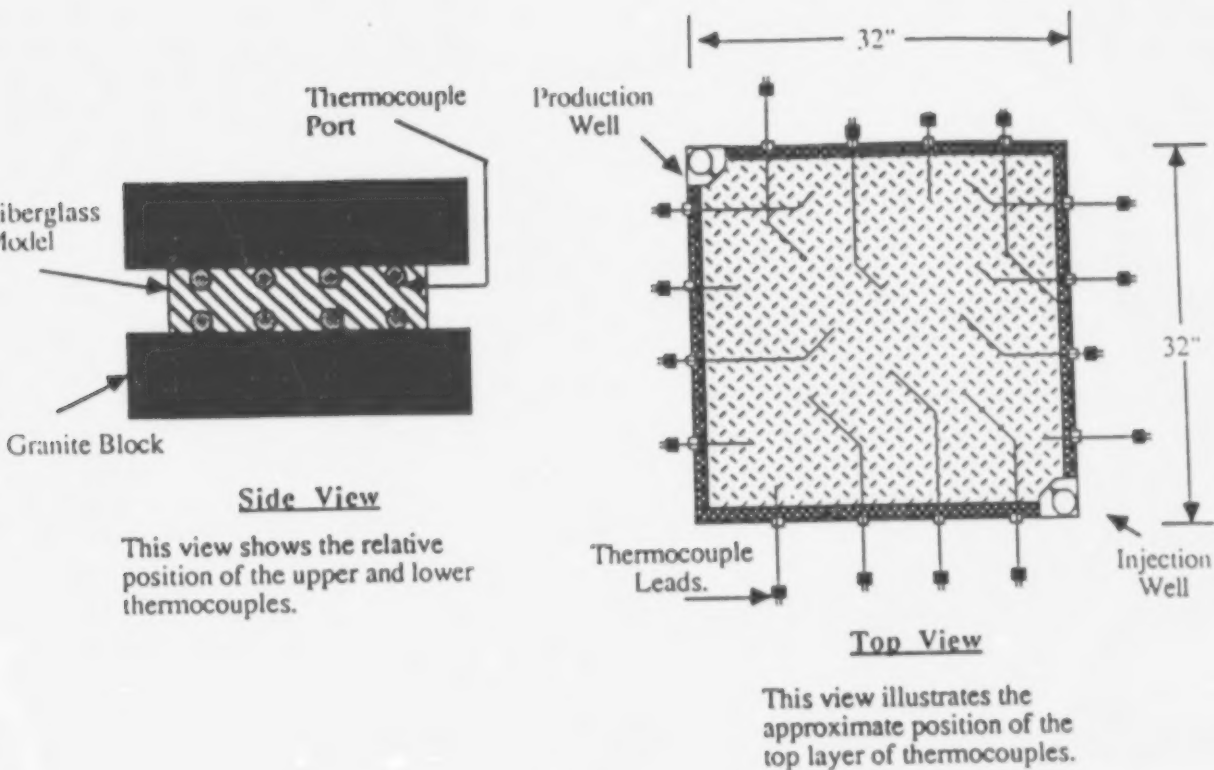


Figure 2. Schematic Diagram of Model Illustrating Thermocouple Positions.

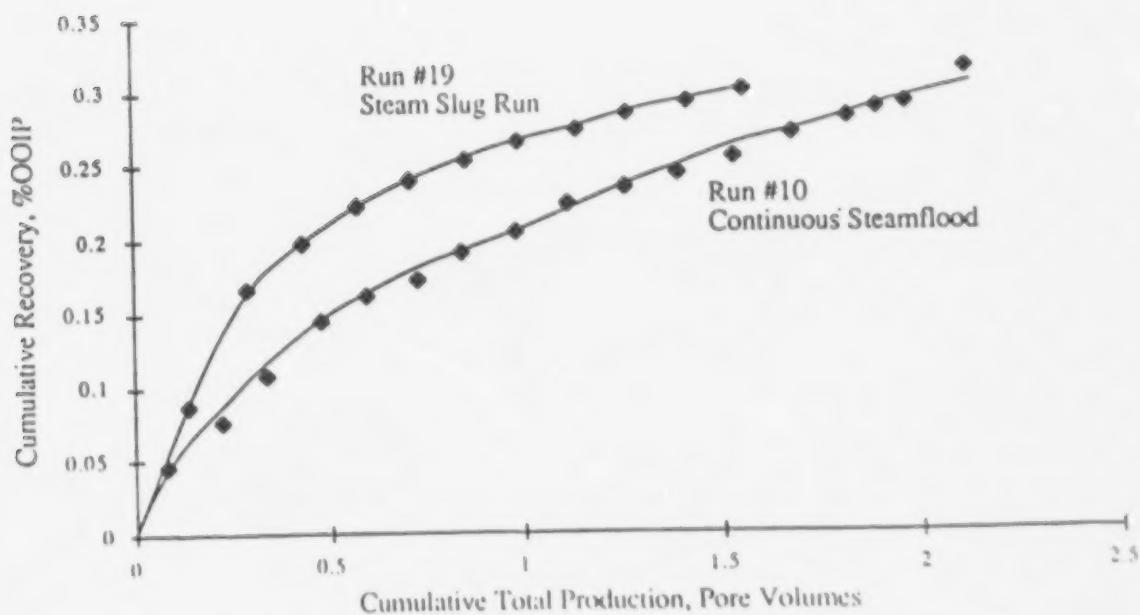


Figure 3. Comparison of the Results of a Continuous Steamflood and a Steam Slug Run, in a Homogeneous Model.

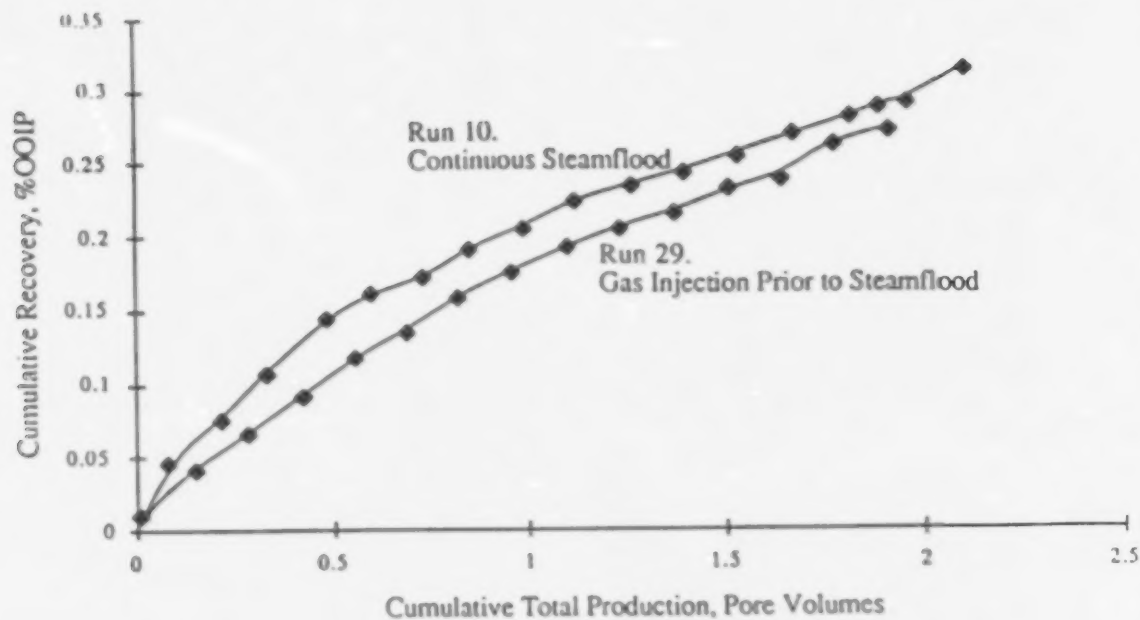


Figure 4. Comparison of the Results of a Continuous Steamflood and a Steamflood Following Gas Injection in a Homogeneous Model.

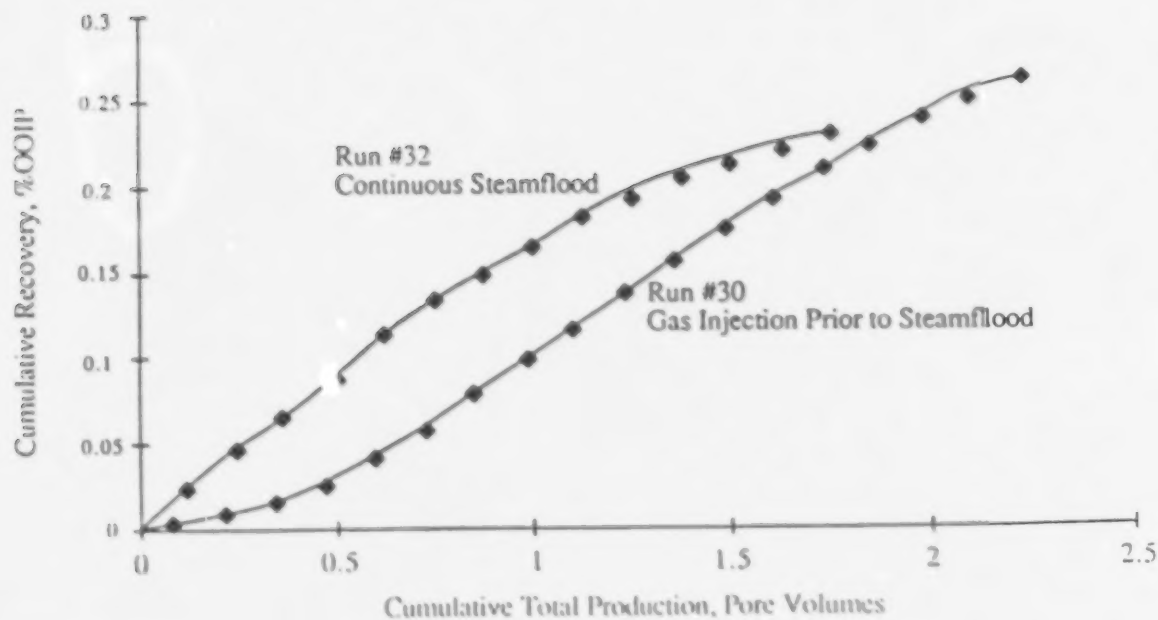


Figure 5. Comparison of the Results of a Continuous Steamflood and a Steamflood Following Gas Injection in a Bottom Water Model.

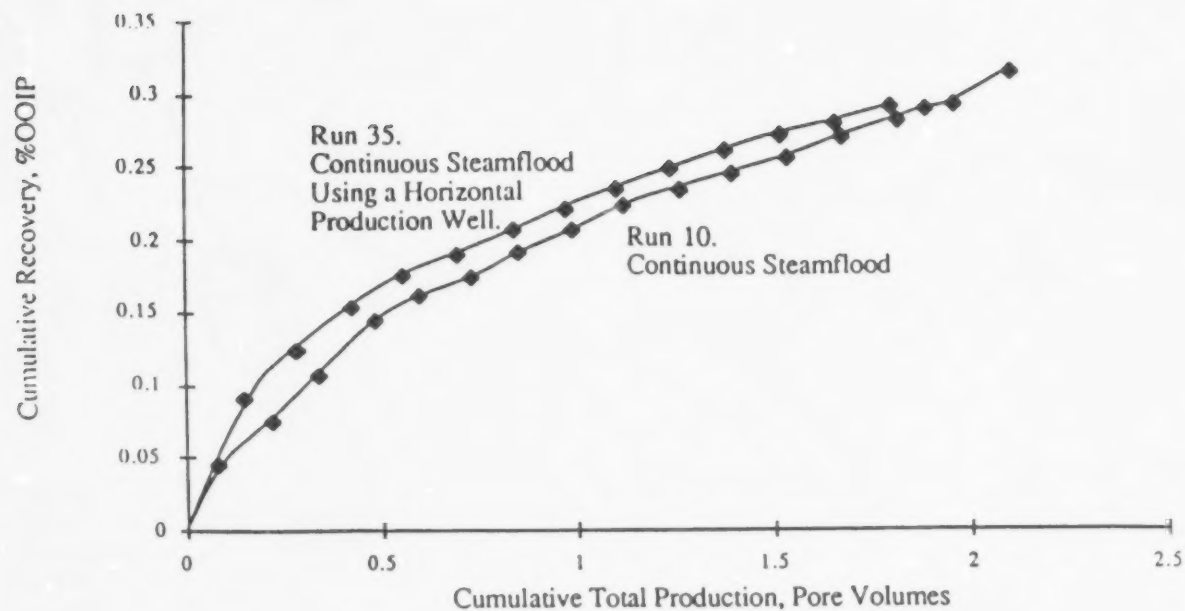


Figure 6. Comparison of the Results of a Continuous Steamflood and a Continuous Steamflood Using a Horizontal Producer in a Homogeneous Model.

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Steam Injection Strategies for Thin, Bottomwater Reservoirs

by M.L. Proctor, U. of Alberta; A.E. George, Energy, Mines & Resources; and S.M. Farouq Ali, U. of Alberta

SPE Members

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ABSTRACT

This paper presents the results of thirty-nine scaled model experiments which were conducted to study variations of steamflooding in thin, heavy oil formations, with bottom water present in many instances. The work primarily addresses Lloydminster, Saskatchewan, type reservoirs which are characterized by a viscous oil (1275 mPa·s at reservoir temperature) and a thin pay (6 ~ 13 meters). Reservoirs of this type are common in Saskatchewan and eastern Alberta; thus it is imperative to develop recovery strategies which are likely to succeed in the field, which was the objective of this research.

Experiments of many types were conducted, many of which gave favorable results. Eight of the thirty-nine experiments were conducted with bottom water models, using strategies based on steamflooding experience gained from the homogeneous model experiments. It was found that by injecting an inert gas into the model, prior to steamflooding, the effect of thick bottom water zones can be minimized. Temperature profiles indicate that the injected gas creates a flow channel away from the water zone, and that the injected steam tends to follow this path of least resistance, rather than channeling directly into the bottom water zone. Injecting gas into a bottom water model, prior to steamflooding improved the oil recovery from 16.79% to 20.66% of the original oil in place.

The experimental results suggest that there is some minimum bottom water thickness (approximately 10% of the gross pay thickness), below which the effect of bottom water is small.

INTRODUCTION

The experimental research project discussed here was undertaken in an attempt to develop recovery

strategies which would effectively recover oil from marginal heavy oil reservoirs, typical of the Lloydminster area of Saskatchewan and eastern Alberta. These heavy oil reservoirs are thin (6 to 13 m) and are commonly associated with bottom water.

A scaled model steamflood apparatus was designed and built, employing the low pressure scaling criteria developed by Stegemeier, Laumbach, and Volek¹. Experiments of many types were conducted, including experiments involving steamfloods following a waterflood, continuous steamfloods into homogeneous packs, continuous steamfloods into bottom water packs, cold water slug runs which entailed the injection of a small volume of steam followed by the continuous injection of cold water, gas injection experiments in bottom water packs in which a small volume of gas was injected into the upper part of the reservoir prior to steam injection, and steamflood experiments which utilized horizontal wells.

It is felt that the steam injection concepts tested in this research will be applicable to many heavy oil reservoirs which are underlain by bottom water, including the Cold Lake heavy oil formations. The relatively low viscosity of the Lloydminster heavy oils, however, offers the prospect of near-term development.

STUDIES OF THIN, BOTTOM WATER RESERVOIRS

Kasraie and Farouq Ali² discussed the mechanisms involved in thermal stimulation of bottom water reservoirs. They stated that although bottom water is undesirable in most instances, it may serve the purpose of providing initial injectivity in very viscous oil formations. Based on their survey of existing field and laboratory data, the authors concluded that a water zone thicker than about one-fifth of the oil zone would make cyclic steam stimulation uneconomical.

References and illustrations at end of paper.

Khosla and Cordell³ performed a numerical simulation study for a 15 meter (49 ft) thick Athabasca tar sand reservoir, of the Fort McMurray, Alberta area. The simulation study was conducted to compare the performance of vertical and horizontal wells for recovering the viscous Athabasca tar sand. Most of the simulations were performed on a spacing of 2.4 ha/well (5.93 acres) with a high water saturation in the bottom 6 meters (19.7 ft) of the reservoir, which provided the necessary steam injectivity. They noted that if the well spacing was doubled (from 50 m to 100 m) and a high permeability streak was introduced between the injector and producer, most of the injected steam would travel through the high permeability streak, giving early steam breakthrough and low oil recovery. Khosla and Cordell concluded that horizontal well processes can perform significantly better than vertical well processes in reservoirs of this type. In reviewing this study, Joshi⁴ concluded that a steam drive using horizontal wells in bitumen reservoirs can be successful only if the bottom water zone has permeability the same or less than the oil zone, there are no high permeability streak zones, and spacing between the wells are close. He suggested that steam assisted gravity drainage may be better suited to such reservoirs.

The Peace River reservoirs modeled by Prats⁵ contain a substantial oil saturation (45%) in the underlying high water saturation layer; thus injection into the mobile bottom water zone may produce an economically acceptable amount of oil. The Cold Lake reservoir studied by Pursley⁶ has a pay thickness of 43 meters (140 feet) and the Wabasca reservoir studied by Huygen and Lowry⁷ has a thin bottom water zone relative to the total pay thickness, and both have viscosities of the order of 10^5 mPa.s. Thus, the results of these three studies may not be representative of thin, bottom water reservoirs such as the Aberfeldy reservoir, modeled in this work.

A numerical simulation study was performed by Singh, Malcolm, and Heidrick⁸ with the objective of evaluating the potential for steam injection and steam injection with additives in reservoirs with bottom water. The project encompassed a number of numerical simulations which were run to determine the effects of bottom water thickness, carbon-dioxide injected along with the steam, blocking agents, and injection-production strategy. The results given are of a very general nature, and do not give any definite guidelines for producing bottom water reservoirs.

EXPERIMENTAL APPARATUS AND PROCEDURE

The apparatus used in this study was designed based on the low pressure scaling criteria of Stegemeier et al.¹ The model was designed to represent one-quarter of an eight hectare (twenty acre) five-spot pattern, and as such, has one injection well and one production well, at diagonally opposite corners. The model was chosen to be 81.3 cm (32 in) square and 6.4 cm (2.5 in) thick, giving a geometric scaling factor of 173.2.

The values listed in Table 1 were chosen to represent the Aberfeldy prototype. These values, and the geometric scaling factor were used to calculate

the operating parameters for the Aberfeldy scaled model which are summarized in Table 2. Note that the time scale is 12.18 minutes in the model for each year in the prototype, thus a great deal of data is produced in a very short time during an experimental run.

A schematic diagram of the apparatus used in this research is presented as Figure 1. The main components of the apparatus are the physical model, the steam injection system, the model cart and cold storage unit, the fluid collection system, and the data acquisition system. A detailed description of the apparatus is contained in References 9 and 10.

Establishing a Bottom Water Layer in the Model

In general, the saturation procedure for the homogeneous models was the same as that described by Stegemeier et al.¹ for their model. However, for bottom water experiments, the saturation procedure was necessarily different. The bottom water layer was established in the model by first packing the model and then adding the volume of water required to obtain the desired bottom water thickness. The model was then placed into a freezer and the beads and water were frozen in place. After freezing, the model was repacked, the model auxiliary apparatus was assembled, a vacuum was applied, and the upper portion of the model was saturated in a manner similar to the homogeneous packs. Six large saturation ports were incorporated into the model (three on each of two opposing sides) to improve the efficiency of the saturation process.

An innovative approach was used to determine the volume of bottom water that had thawed and been displaced during the saturation process. The bottom layer was made up of a 5% solution of NaCl, and by measuring the refractive indexes of this solution, distilled water, and the sample displaced during saturation, the volume of bottom water remaining in the model after saturation could be determined. By the same method, the volume of bottom water produced during the steamflood experiment could also be determined.

The thickness of the bottom water layer remaining after oil saturation was difficult to control. As can be seen in Table 3, the bottom water thicknesses ranged from 2.3% to 19.7%.

After the saturation process was complete, the apparatus was simply rolled into a cooler on a cart and rail system, where it was left for 36 to 48 hours until it reached the low initial temperature of 3° C required by the scaling groups.

Data Analysis

The model is equipped with 32 thermocouples, positioned in two layers. More thermocouples placed in even more layers within the model would be desirable, but geometric scaling limits the model to a thickness of 6.4 cm (2.5 in), which is not adequate for more than two layers of thermocouples. During an experiment, these thermocouples were scanned by the data acquisition unit once every thirty seconds and the readings were used to generate temperature profiles illustrating the heat advance in the model.

Following each experiment, the data analysis included generating a table of instantaneous and cumulative production as functions of pore volumes of cumulative production, plotting cumulative recovery and instantaneous oil and water recoveries as functions of pore volumes of cumulative production, and generating temperature profiles for each 0.25 pore volumes of cumulative production.

The tables and plots generated from this analysis were then examined to determine the efficacy of each of the processes under investigation and to indicate whether the given strategy was suitable for recovering heavy oil from thin, bottom water reservoirs.

DISCUSSION OF THE RESULTS

A low pressure scaled physical model was employed for 39 steamfloods of various types. Table 3 lists the types of experiments conducted, along with information concerning the initial model conditions and the experimental results. It can be seen that the vacuum scaled model is capable of representing a large variety of situations and enables one to experiment with numerous steamflooding strategies.

The first four steamflood experiments were conducted in models saturated with 100% water. The purpose of these experiments was to examine the model and overall system operation, and to observe the general pattern of flow distribution.

In general, most of the steamflood experiments were conducted with steam temperature and pressure of about 65° C (149° F) and 24 kPa (3.5 psia), respectively, and a steam quality of about 70%. To represent a prototype steam injection rate of 100 m³/day, the model injection rate was 1/4 (because the model represents 1/4 of a five-spot) of 907.3 cm³/min (as given by the rate scale in Table 2), which is 226.8 cm³/min. The experiment was usually continued until about two pore volumes of steam had been injected.

Several steamflood strategies were considered in an attempt to develop methods suitable for recovering oil from the marginal heavy oil reservoirs typical of Lloydminster. The first phase of this research involved experiments in homogeneous packs, without bottom water.

In homogeneous packs, the cold water slug runs (Runs 17, 18, and 19) gave favorable results, generally better than the continuous steamfloods. These experiments entailed injecting steam into the model until the point where a sharp drop in the oil-steam ratio was observed. Then cold water was injected. The water was injected at a temperature of 4° C to coincide with the scaling criteria.

Steam Slug Runs

Figure 2 compares the results of a typical steam slug run with a typical continuous steamflood experiment, in homogeneous models. It can be seen that the recovery by the steam slug process is better than that for the continuous steamflood for all values of cumulative production, although, it would appear as though both processes approach the same ultimate recovery. Considering that a much smaller volume of steam is required for the steam slug process,

it would be economically more favorable than continuous steamflooding. Judging from these experiments, the steam slug process appears to be a viable recovery technique for the Aberfeldy reservoir.

Horizontal Wells

Three steamflood experiments were conducted using horizontal wells. Two of these experiments used a horizontal injector and a horizontal producer set in opposite sides of the model to give a steam drive with parallel horizontal wells. The recovery from these two experiments was similar to that of the continuous steamfloods using vertical wells. The third horizontal well experiment utilized a vertical injector and a horizontal producer for the steam drive. This combination proved to be significantly better than the steam drive with parallel horizontal wells, recovering 29% versus 25% of the original oil in place, after injecting 1.8 pore volume of steam. These horizontal well experiments produced good results, perhaps better than the vertical well steamfloods, but the difficulty and added expense of placing horizontal wells in a thin reservoir may limit the applicability of this process.

Gas Injection

It was hypothesized that the injection of a small amount of an inert gas prior to steamflooding may create a flow channel away from the bottom water zone, thereby minimizing the heat scavenging effect of the bottom water. This hypothesis was first tested in a homogeneous pack where it was found that the gas injection process may even be suitable in some reservoirs without bottom water. This strategy has the advantage of dramatically improving steam injectivity and thus may be suitable in reservoirs where the desired steam injectivity cannot be achieved. Figure 3 compares the production response for continuous steam injection and steam injection following gas injection in a homogeneous model. It can be seen that the production response of the gas injection process is slightly lower than that of the continuous steam injection process. However, in a reservoir where steam injectivity is a problem, the injectivity improvement obtained by gas injection may justify the small decrease in oil recovery.

Bottom Water Runs

Eight experiments were conducted in models with bottom water layers. As noted previously, the bottom water thickness ranged from 2.3 to 19.71% of the total reservoir thickness. Four successful continuous steamflood experiments were performed in models with bottom water. Although there is not sufficient data to draw far reaching conclusions, these runs seem to indicate that there is a minimum bottom water thickness below which the effect of bottom water is small. Figure 4 plots the oil recovery for each of the four continuous steamflood experiments at 1.75 pore volumes of cumulative production against the bottom water thickness in the model, as a percentage of the total model thickness. From this plot it can be seen that with a bottom water thickness less than about 10% of the total model thickness, the steamflood oil recovery is similar to the continuous steamfloods in homo-

geneous packs. However, for a bottom water thickness of greater than 10% of the total model thickness, oil recovery is greatly reduced.

Gas Injection With Bottom Water

Steam injected into reservoirs underlain by relatively thick bottom water (greater than 10% of the gross pay) often channels directly into the bottom water zone, drastically reducing the effectiveness of the steamflood process. As mentioned previously, it was hypothesized that by injecting an inert gas prior to steam injection, a flow channel away from the bottom water will be created for the steam, thus reducing the detrimental effect of the bottom water. Seven gas injection experiments were conducted, four in homogeneous models and three in bottom water models. These experiments involved injecting gas at 14 kPa (2 psia) for a short time (typically 4 to 5 minutes) until the oil production was insignificant. The results of these experiments appear to support the hypothesis.

Figures 5 and 6 give temperature profiles for an injector to producer cross-section for a gas injection steamflood experiment (Run 38) and a straight steamflood experiment (Run 39), respectively, at 0.25 pore volumes of steam injected. Figures 7 and 8 give temperature profiles for Runs 38 and 39, respectively, at 1.50 pore volumes of steam injected. Figure 6 shows that the heat advances immediately into the lower portion of the model for the continuous steamflood without gas injection. Figure 5, for the gas injection experiment at the same stage of steam injection, shows a nearly vertical heat advance in the model. Figure 8, for the straight steamflood experiment after 1.50 pore volumes of steam was injected, shows that the heat continues to advance more rapidly in the lower portion of the model. Figure 9, for the experiment involving gas injection prior to steamflooding, after 1.50 pore volumes of steam was injected, shows that the heat is still quite evenly distributed between the upper and lower portion of the model.

These temperature profiles indicate that without gas injection prior to steamflooding, the steam channeled directly into the bottom water layer, but that with gas injection this problem was mitigated. Whether the gas provided a path at the top of the bead pack, or whether the path was created at the oil water interface is uncertain, due to the limited resolution that can be obtained with only two layers of thermocouples. A thicker model would allow for more layers of thermocouples, but the geometric scaling in the vertical dimension would be lost.

The most significant result of these gas injection experiments in bottom water models, was that the oil recovery response was significantly improved. Figure 9 graphically compares the recovery response of continuous steamflooding with (Run 38) and without (Run 39) gas injection prior to steamflooding, in a bottom water reservoir. The steamflood production response for the gas injection experiment is significantly better than the straight steamflood experiment. The ultimate oil recovery is also considerably higher. These results are valid for the oil viscosity simulated (1275 mPa.s), and

possibly for lower viscosities. For higher oil viscosities, the beneficial effect of gas would probably be less evident.

CONCLUSIONS

1. The steam slug process appears to be an efficient and practically viable recovery process for thin heavy oil reservoirs of the Aberfeldy type.
2. For thin, heavy oil reservoirs with bottom water, the injection of a small volume of an inert gas prior to steam injection may be a suitable method for improving steamflood performance. The injected gas appears to create a flow channel away from the bottom water and allows for a more efficient heating of the reservoir.
3. The results of the experiments indicate that there is some minimum bottom water thickness, approximately 10% of the gross pay thickness, below which the effect of bottom water is small.
4. Steam drive experiments utilizing horizontal wells produced favorable results although the difficulty and added expense involved in placing horizontal wells in thin heavy oil formations may limit the applicability of this process. However, the results of these horizontal well experiments were encouraging and warrant further investigation into the modeling of horizontal well processes in bottom water situations.

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The capable assistance of Mr. Daniel Oracheski, who helped conduct experiments and process experimental data, is also appreciated.

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Table 1. Prototype Reservoir Data

Net Pay Thickness:	11 m (36 ft)
Porosity:	0.31
Permeability:	2000 md
Thermal Conductivity:	0.002077 k W/(m•K) (1.2 Btu/hr•ft•°F)
Heat Capacity:	2.2217 kJ/(kg•K)
Initial Saturation:	$S_o=0.75$, $S_g=0.02$, $S_w=0.23$
Steamflood Residual Oil Saturation:	$S_{or}=0.15$
Oil Viscosity:	1275 mPa•s at 23.9 °C (75 °F)
Water Viscosity:	0.891 mPa•s at 25.8 °C (78.4 °F)
Initial Reservoir Temperature:	23.3 °C (74 °F)
Steam Injection Pressure:	1.900 MPa (275.5 psi)
Steam Injection Rate:	100-150 m ³ /day (630-945 bbl./day)
Steam Quality:	0.70 (Actually is 0.80 but a lower value was chosen to allow for wellbore heat losses.)

Table 2. Summary of the Scaling Calculations for the Aberfeldy Model

Length Scale:	$\gamma(L) = L_p/L_m = 173.2$
Pressure Relation:	$P_m = 0.004683 + 0.006415 P_p$ (MPa)
Temperature Relation:	$T_m = 0.286 T_p - 3.657$ (°C)
Time Scale:	$t_m/t_p = 12.18$ minutes/year
Permeability:	prototype = 2 darcies model = 4216.5 darcies
Injection and Production Rate Scales:	$w_m/w_p = 9.0728$ (cm ³ /min)/(m ³ /day)
Initial Model Temperature:	30°C
Model Pressure:	Production end: 7 kPa (1 psia) Injection end: Near atmospheric pressure.

Table 3. List of Experiments

Run #	Model Type	Process	Porosity (%)	Sol (%)	Swt (%)	Cum Rec (%OOIP)	Cum PV Inj
1	Homogeneous Model (Water Sal.)	PE		0.00	100.00	NA	NA
2	Homogeneous Model (Water Sal.)	PE		0.00	100.00	NA	NA
3	Homogeneous Model (Water Sal.)	PE		0.00	100.00	NA	NA
4	Homogeneous Model (Water Sal.)	CS	32.40	0.00	100.00	NA	NA
5	Homogeneous Aberfeldy Model	CS	33.80	86.74	13.26	6.59	0.4500
6	Homogeneous Aberfeldy Model	CS	33.30	84.49	15.51	21.89	2.3400
7	Homogeneous Aberfeldy Model	Cold WF	31.00	90.41	9.59	22.52	1.1730
7B	Homogeneous Aberfeldy Model	Room Temp. WF	31.00			26.47	1.6750
7C	Homogeneous Aberfeldy Model	CS	31.00			32.40	2.8670
8	Homogeneous Heavy Oil (13000cp) Model	UR	35.90	NA		NA	NA
9	Homogeneous Heavy Oil (13000cp) Model	CS	32.90	87.68	12.32	1.65	1.0100
10	Homogeneous Aberfeldy Model	CS	30.20	92.00	8.00	31.38	2.1140
11	Homogeneous Light Oil (25.6cp) Model	UR (Vacuum Leak)	30.80	85.28	14.72	NA	NA
12	Homogeneous Light Oil (25.6cp) Model	CS	33.50	89.22	10.78	32.95	1.4356
13	Homogeneous Light Oil (25.6cp) Model	CS	30.10	92.18	7.82	35.52	1.6524
14	Homogeneous Aberfeldy Model	UR (Vacuum Leak)	33.10	90.22	9.78	NA	NA
15	Bottom Water Aberfeldy Model	CS	35.90	76.34 (avg.)	23.66 (avg.)	3.08	1.2100
16	Homogeneous Aberfeldy Model	UR (Vacuum Leak)	32.40	93.47	6.53	NA	NA
17	Homogeneous Aberfeldy Model	WF Following a SS	32.90	92.62	7.38	24.22	1.0310
18	Homogeneous Aberfeldy Model	WF Following a SS	33.00	92.00	8.00	30.85	1.4440
19	Homogeneous Aberfeldy Model	WF Following a SS	33.30	91.52	8.48	30.07	1.5600
20	Homogeneous Aberfeldy Model	UR (Prod. Well Plugging)	32.10	93.41	6.59	NA	NA
21	Homogeneous Aberfeldy Model	UR (Prod. Well Plugging)	32.50	94.36	5.64	NA	NA
22	Homogeneous Aberfeldy Model	Hot WF	34.10	89.45	10.55	25.91	1.3540
23	Homogeneous Aberfeldy Model	CS	33.09	89.53	10.47	39.94	2.1072
24	Homogeneous Aberfeldy Model	GI Prior to SF	33.52	94.03	5.97	29.57	1.8548
25	Homogeneous Aberfeldy Model	GI Prior to SF (inj. into upper model)	33.34	94.68	5.32	26.58	1.8533
26	Homogeneous Aberfeldy Model	CS (inj. into upper model)	33.46	94.77	5.23	31.76	1.9719
27	Homogeneous Aberfeldy Model	CS	33.29	95.10	4.90	32.18	2.2513
28	Homogeneous Aberfeldy Model	UR (Run spoiled by damaged boiler)	32.65	92.53	7.47	NA	NA
29	Homogeneous Aberfeldy Model	GI Prior to SF	33.50	89.41	10.59	27.34	1.9200
30	Bottom Water Aberfeldy Model	GI Prior to SF (inj. into upper model)	36.09	75.96 (avg.)	24.04 (avg.)	26.18	2.2296
31	Bottom Water Aberfeldy Model (BW=9.1%)	CS (Inj.-I, Prod.-I)	36.66	89.77 (avg.)	10.23 (avg.)	27.67	1.8406
32	Bottom Water Aberfeldy Model (BW=2.3%)	CS (Inj.-I, Prod.-I)	34.01	95.36 (avg.)	4.64 (avg.)	22.75	1.8712
33	Bottom Water Aberfeldy Model (BW=4.0%)	CS (inj. into lower model)	37.33	86.70 (avg.)	13.30 (avg.)	22.91	1.7592
34	Homogeneous Aberfeldy Model	Horizontal Inj. and Prod. Wells	32.76	93.64	6.36	25.96	1.9800
35	Homogeneous Aberfeldy Model	Horizontal Prod. Well, Vertical Injector	33.47	91.36	8.64	29.00	1.8055
36	Homogeneous Aberfeldy Model	Horizontal Inj. and Prod. Wells	34.00	90.44	9.56	24.78	1.7840
37	Bottom Water Aberfeldy Model (BW=11.2%)	GI Prior to SF (Inj.-I, Prod.-entire int.)	36.07	85.25 (avg.)	14.75 (avg.)	20.94	1.9805
38	Bottom Water Aberfeldy Model (BW=19.2%)	GI Prior to SF (Inj.-entire int., Prod.-I)	36.91	84.91 (avg.)	15.09 (avg.)	20.66	1.8262
39	Bottom Water Aberfeldy Model (BW=12.5%)	CS (Inj.-entire int., Prod.-I)	37.09	86.01 (avg.)	13.99 (avg.)	16.79	1.7827

PE = Preliminary Experiment
CS = Continuous Steamflood
UR = Unsuccessful Run
WF = Waterflood

SF = Steamflood
GI = Gas Injection
SS = Steam Slug

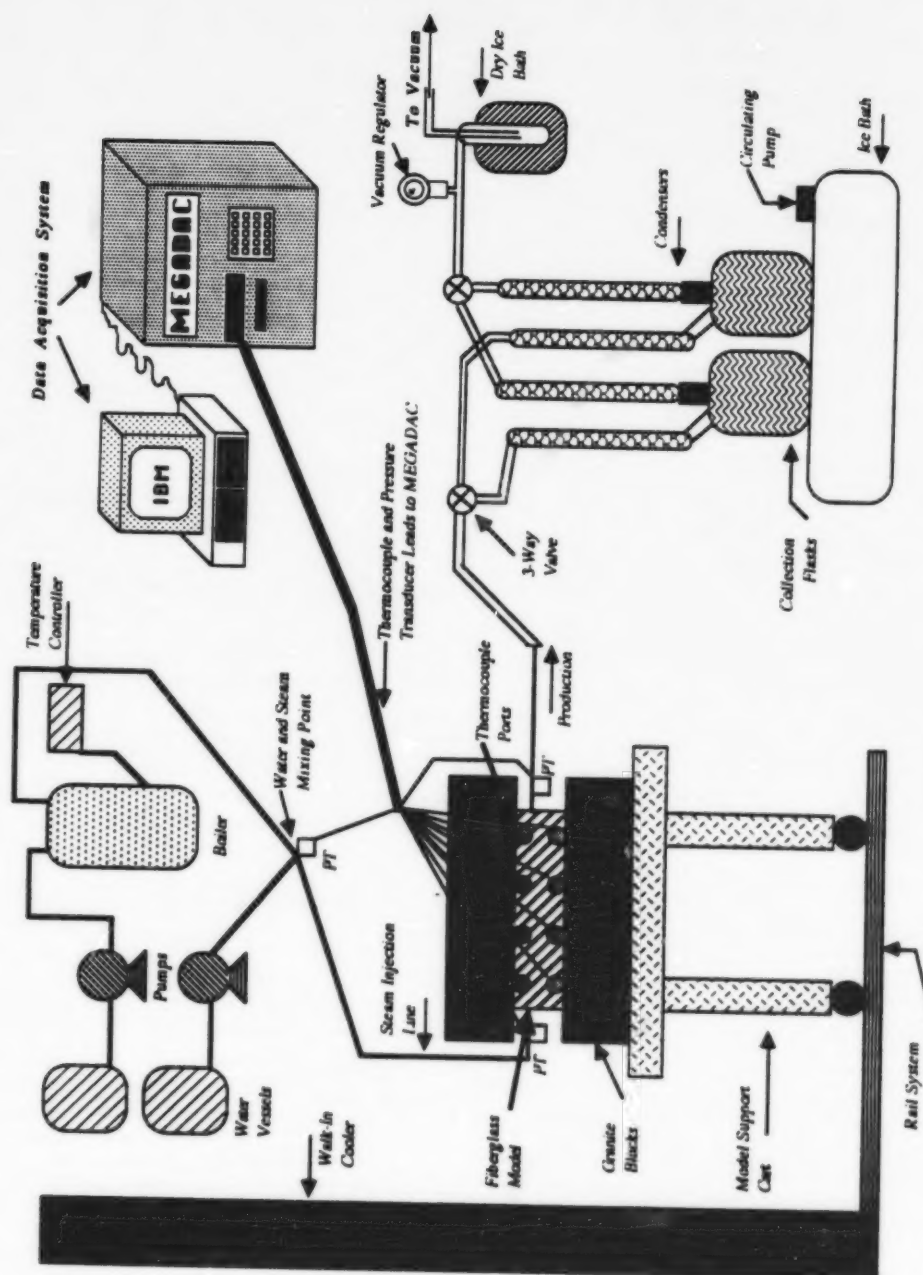


Fig. 1—Schematic diagram of apparatus.

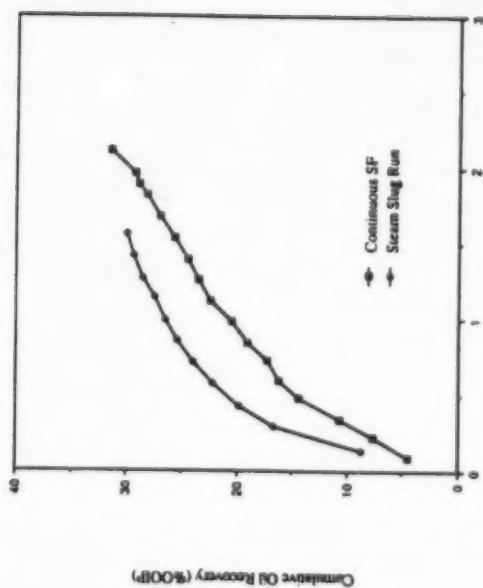


Fig. 2—Recovery comparison of the steam slug process and continuous steamflood (Run 18 vs. Run 19).

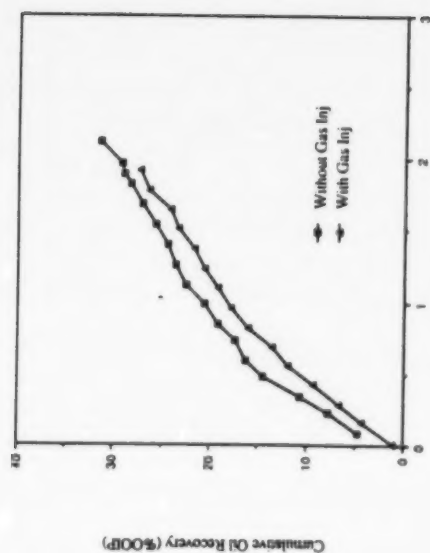


Fig. 3—Recovery comparison for steamflood with and without gas injection in a homogeneous reservoir (Run 29 vs. Run 10).

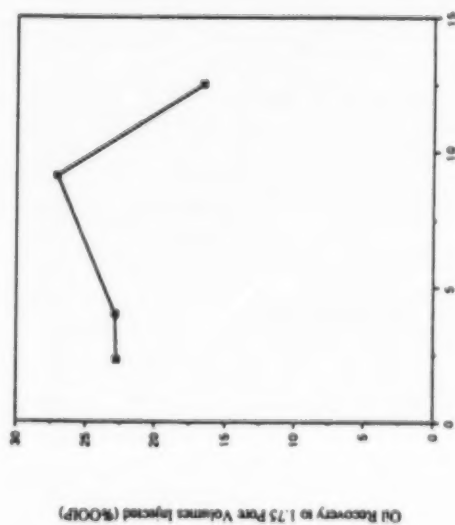


Fig. 4—Effect of bottomwater thickness on continuous steamflood recovery.

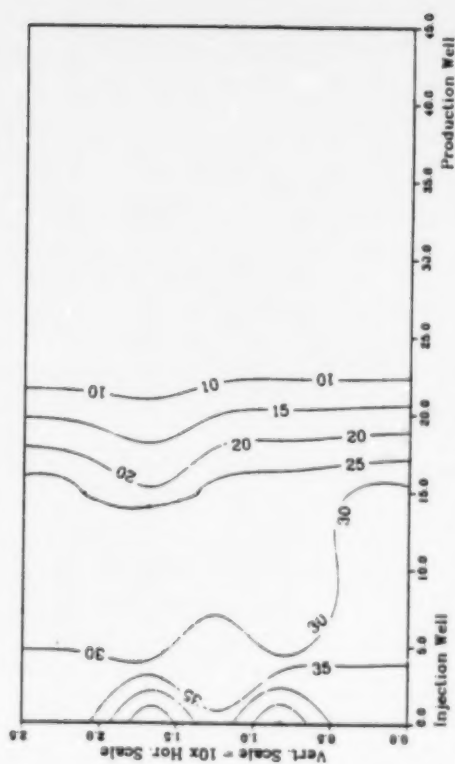


Fig. 5—Injector to produce cross-section temperature profile for a continuous steamflood in a bottomwater reservoir after injecting 0.25 PV's.

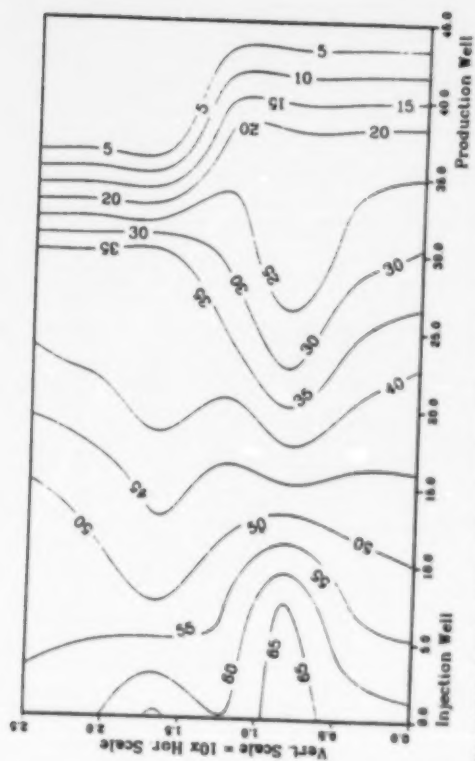


Fig. 7—Isopter to produce cross-section temperature profile for a continuous steamflood in a bottomwater reservoir after injecting 1.50 PV's.

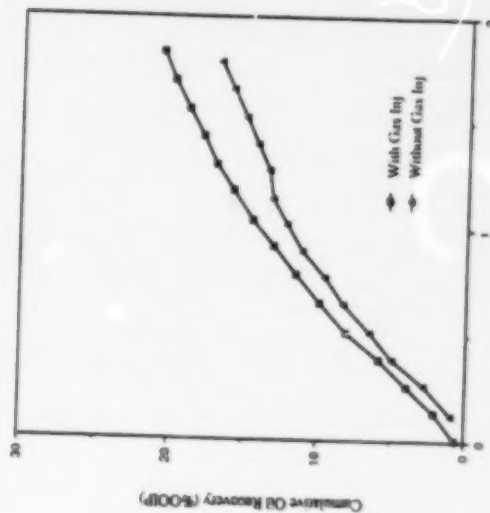


Fig. 9—Recovery comparison for steamflood with and without gas injection in a bottomwater reservoir (from 38 to 48 PV's).

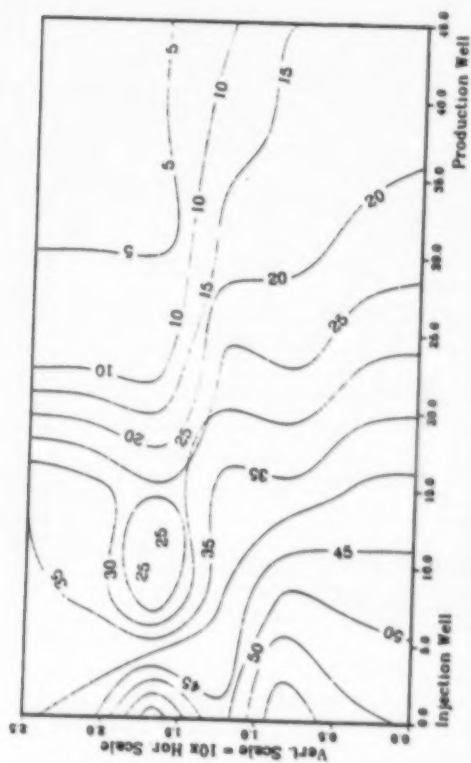


Fig. 6—Isopter to produce cross-section temperature profile for a gas injection experiment in a bottomwater reservoir after injecting 0.35 PV's of steam.

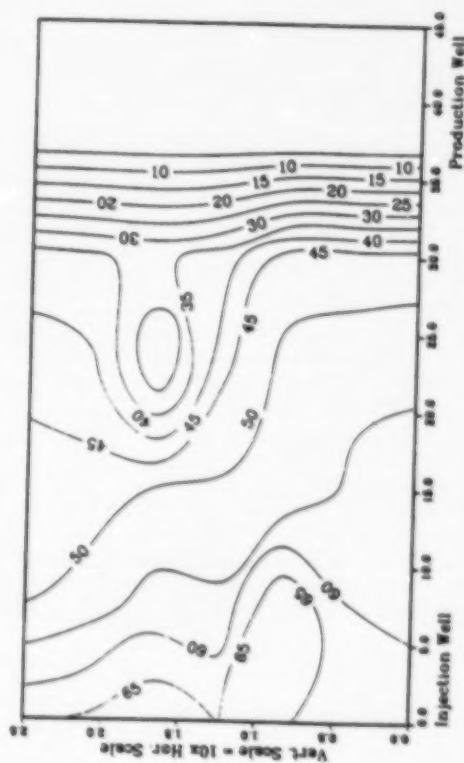


Fig. 8—Isopter to produce cross-section temperature profile for a gas injection experiment in a bottomwater reservoir after injecting 1.00 PV's of steam.